

Wyoming Carbon Capture, Utilization, and Storage (CCUS) Study

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For

United States Department of Energy
Office of Fossil Energy

August 2020

The study was conducted with contributions from the Department of Energy, Office of Fossil Energy (DOE-FE), the National Energy Technology Laboratory (NETL), Management Information Services Inc. (MISI), University of Wyoming School of Energy Resources' (SER), Center for Economic Geology Research (CEGR), and Enhanced Oil Recovery Institute (EORI).

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Contents

Glossary.....	v
Executive Summary.....	1
1 Introduction.....	7
1.1 Background.....	7
1.1.1 Rocky Mountain Power	8
1.2 Study Outline and Objectives.....	10
2 State of Wyoming CCUS Policy, Infrastructure, and Geologic Considerations	12
2.1 Federal CCUS Policy.....	12
2.2 Wyoming CCUS Policy.....	13
2.3 Wyoming Laws Impacting CCUS Retrofits.....	14
2.3.1 Senate File 0159 (2019)	14
2.3.2 House Bill 0200 (2020).....	14
2.4 CCUS Infrastructure in Wyoming.....	16
2.4.1 Public Acceptance.....	17
2.4.2 Out-of-State Markets and Low-Carbon Emission Standards.....	17
3 Regional CO ₂ Markets, Pipeline, and Storage Opportunities	20
3.1 Current CO ₂ Market.....	20
3.2 Pipeline Infrastructure.....	22
3.3 CO ₂ Storage Options, EOR Opportunities	24
4 Techno-Economic Analysis.....	29
4.1 Scenarios Modeled.....	29
4.2 Overview of Power Plants Considered for Analysis.....	29
4.3 CCUS Retrofit Cost Calculation.....	31
4.3.1 Assumptions and Methodology.....	31
4.3.2 Results - CCUS retrofit costs.....	32
4.4 SimCCS Data Analysis.....	34
4.4.1 Assumptions and Methodology.....	34
4.4.2 45Q Tax Credit Application.....	35
4.4.3 EOR Field Inputs and Methodology.....	35
4.4.4 Saline Site Inputs and Methodology	36
4.4.5 SimCCS Modeling Runs	37

4.5	SimCCS Results.....	38
4.5.1	Scenario A.....	38
4.5.2	Scenario B.....	39
4.5.3	Scenario Comparison.....	41
4.6	Summary of Cost Analyses.....	42
4.7	Summary of TEA Findings.....	44
5	Jobs and Economic Impact Analysis.....	45
5.1	Assumptions and Methodology.....	45
5.2	Job Impact Analysis Results.....	45
6	Regional Electricity and Environmental Market.....	50
6.1	Introduction.....	50
6.2	California Cap-and-Trade Market and the Energy Imbalance Market (EIM).....	51
6.3	WECC with a Focus on Wyoming and PacifiCorp.....	51
6.3.1	Future Power Generation in WECC.....	51
6.3.2	Future Power Generation in Wyoming and PacifiCorp.....	52
6.4	Dispatch Analysis Using PROMOD.....	54
6.4.1	Assumptions.....	54
6.4.2	Methodology.....	55
6.4.3	Dispatch Analysis Results.....	56
6.4.4	Scenario Comparison.....	60
7	Appendices.....	63
7.1	Capacity factor for W A Parish CO ₂ capture project (Unit 8).....	64
7.2	Details of the EOR modeling study.....	65
7.3	Design and technical aspects of SimCCS.....	67
7.3.1	Design and Technical Aspects of SimCCS.....	67
7.3.2	Analyses Run Using SimCCS.....	68
7.3.3	Outputs parameters generated by SimCCS.....	68
7.3.4	Post-processing of SimCCS results.....	69

List of Figures

Figure EX-1: Wyoming CO ₂ Emissions.....	2
Figure EX-2: Job Impact Analysis by Year.....	3
Figure EX-3: Comparative Annual Wyoming Job Impacts	4
Figure EX-4: Wyoming Plant Locations.....	5
Figure 1: Survey Summary – Wyoming’s Energy Future.....	17
Figure 2: States and Utilities with Decarbonization/Clean Energy Mandates/Goals	18
Figure 3: Wyoming CO ₂ Sales for Natural Gas Processing.....	21
Figure 4: Wyoming Pipeline Infrastructure	23
Figure 5: Wyoming Oilfields and Natural Gas Processing Facilities.....	25
Figure 6: Structural Geologic Model of the Rock Springs Uplift.	27
Figure 7: CCUS Retrofit Capital Costs.....	32
Figure 8: Scenario A SimCCS Workflow.....	34
Figure 9: SimCCS Scenario A Solution	39
Figure 10: SimCCS Scenario B Solution.....	40
Figure 11: Capex by County – Scenarios A&B (A on the left, B on the right).....	41
Figure 12: O&M Costs by County – Scenarios A&B (A on the left, B on the right).....	41
Figure 13: Pipeline Capex by County – Scenarios A&B.....	42
Figure 14: Job Impact Analysis by Year	45
Figure 15: Relative Job Impacts in 2025 by County	46
Figure 16: Average Long-Term Job Impacts By County (2026-2055).....	47
Figure 17: Average Annual Net Job Differences of Baseline IRP Scenario (2026-2038).....	48
Figure 18: PacifiCorp Planned Retirements and New Generation Capacity.....	53
Figure 19: Summer Capacity of the IRP preferred portfolio (MW) ⁹⁰	54
Figure 20: Capacity Balance for the Baseline IRP Scenario	56
Figure 21: WECC Available Generation Capacity with Historical Natural Gas Capacity	57
Figure 22: Wyoming CO ₂ Emissions.....	58
Figure 23: Captured CO ₂ Emissions with CCUS.....	58
Figure 24: Change in On-Peak LMP vs Baseline IRP Scenario.....	59
Figure 25: Comparison of Fuel Consumption.....	60
Figure 26: Capacity factor for the Petra Nova CCUS project.....	64

List of Tables

Table 1: Planned Retirement Dates for PacifiCorp Wyoming Coal Plants.....	8
Table 2: CO ₂ Sold in Wyoming and Montana.....	22
Table 3: Storage Characteristics of Sedimentary Basins in Wyoming.....	26
Table 4: Design Data for PacifiCorp Units.....	30
Table 5: Summary of TPC, TOC, and Breakeven Costs for CCUS Retrofits (2011 Dollars).....	33
Table 6: Total System Capture, Transport, and Injection Costs (2020 Dollars).....	38
Table 7: Inputs for the Discounted Cash Flow (DCF) Analysis (2020 Dollars)	43

Table 8: Impacts of CCUS Retrofits on the Costs of Electricity	44
Table 9: PacifiCorp Wyoming Coal-Fired Power Plants.....	50
Table 10: WECC Projections to 2038.....	51
Table 11: PacifiCorp Summer Obligations.....	52
Table 12: PROMOD Scenarios for WECC Analysis.....	55
Table 13: Scenario Resource Mix (Compared to 2019)	61

Glossary

CCUS	Carbon capture, utilization, and storage	EIA	Energy Information Administration
ABB	Asea Brown Boveri	EIM	Energy imbalance market
ACE	Affordable Clean Energy	EIS	Environmental impact statement
AEO	Annual Energy Outlook	EOR	Enhanced oil recovery
ARI	Advanced Resources International Inc.	EORI	Enhanced Oil Recovery Institute
ATWACC	After-tax weighted average cost of capital	EPA	Environmental Pollution Agency
BA	Balancing authority	EPS	Emission Performance Standards
BLM	Bureau of Land Management	FE	Office of Fossil Energy (DOE)
BPA	Bonneville Power Administration	FEED	Front-end engineering design
BPS	Bulk Power System	FERC	Federal Energy Regulatory Commission
CA	California Independent System Operator	FGD	Flue gas desulfurization
CAA	Clean Air Act	FRED	Federal Reserve Economic Data
CAISO	California Independent System Operator	GDP	Gross Domestic Product
CCA	Cedar Creek Anticline	GDPPCTPI	Gross Domestic Product Consumer Price Deflator
CCRD	Carbon capture retrofit database	GHG	Greenhouse gas
CCS	Carbon capture and storage	GIS	Geographic information system
CEGR	Center for Economic Geology Research	GUI	Graphical user interface
CEMS	Continuous emission monitoring systems	GW	Giga watts
CERPA	Center for Energy Regulation and Policy Analysis	HB	House bill
CF	Capacity factor	ID	Idaho
CO	Carbon monoxide	IGCC	Integrated gasification combined cycle
COE	Cost of electricity	IRP	Integrated resource plan
CPLEX	IBM ILOG CPLEX optimization studio	IRS	Internal Revenue Service
CUSP	Carbon Underground Storage Project	JB	Jim Bridger
DCF	Discounted cash flow	LANL	Los Alamos National Laboratory
DEQ	Department of Environmental Quality (WY)	LLC	Limited liability company
DJ	Dave Johnston	LMP	Locational-marginal price
DOE	Department of Energy	LNB	Low-NOx burners
		LTI	Leonardo Technologies Inc.
		LTRA	Long-term resource attachment
		MISI	Management Information Services Inc.

MM	Million	TOC	Total overnight costs
MMT	Million metric tonnes	TPC	Total plant cost
MRV	Measurement, Reporting and Verification	TPY	Tonnes per year
MT	Montana	UIC	Underground injection control
MVA	Monitoring, Verification, and Accounting	USGS	United States Geological Survey
MW	Megawatt	UW	University of Wyoming
NAD	North American Datum	VREVI	Variable renewable energy resources
NERC	North American Electric Reliability Corporation	WAPAVRE	Western Area Power Administration Variable renewable energy resources
NETL	National Energy Technology Laboratory	WEAWAPA	Wyoming Energy Authority
NPV	Net Present Value	WECCWEA	Western Electricity Coordinating Council Wyoming Energy Authority
OFA	Overfire Air	WPCIWECC	Wyoming Pipeline Corridor Initiative Western Electricity Coordinating Council
ORRI	Overriding Royalty Interest	WSGSWPCI	Wyoming State Geological Survey Wyoming Pipeline Corridor Initiative
PC	Pulverized Coal	WYWSGS	Wyoming State Geological Survey
PRB	Powder River Basin	WY	Wyoming
PSC	Public Service Commission		
RCW	Revised Code of Washington		
RSU	Rock Springs Uplift		
SCR	Selective catalytic reduction		
SDA	Spray Dryer Absorber		
SER	School of Energy Resources		
SF	Senate File		
TCF	Trillion cubic feet		
TEA	Techno-economic analysis		

Executive Summary

In 2019, Governor Gordon of Wyoming requested the U.S. Department of Energy conduct a carbon capture, utilization and storage (CCUS) study for some of the state's coal fueled power plants. The objective of this study was to conduct an evaluation of CCUS, the potential opportunities for retrofitting existing power plants, the economic impact, and carbon dioxide (CO₂) emissions reductions for the State of Wyoming compared to an alternative case in the most recent PacifiCorp 2019 integrated resource plan (IRP). The study showed CCUS retrofits provided the following potential benefits:

- Reduced CO₂ emissions by 37% (100 million metric tons) more than the 2019 IRP preferred portfolio (henceforth referred to as Baseline IRP),
- CO₂ emissions avoided costs are \$24 per ton (\$21.5/metric ton) less expensive than the Baseline IRP,
- Ratepayers could pay approximately 10% less per month than the Baseline IRP,
- Wyoming employment benefits are up to 5 times higher than employment benefits from implementing the Baseline IRP),
- Higher local and state revenue from property, sale, severance, and other associated coal taxes as well as federal royalty payments.

The study was conducted with contributions from several organizations. The team was led by Department of Energy, Office of Fossil Energy (DOE-FE) staff and included the National Energy Technology Laboratory (NETL), Leonardo Technologies Inc. (LTI), Management Information Services Inc. (MISI), University of Wyoming School of Energy Resources' (SER) Center for Economic Geology Research (CEGR), and Enhanced Oil Recovery Institute (EORI).

The scope of the study is to consider the retrofit of nine units at four power plants in Wyoming, owned by Rocky Mountain Power¹, a PacifiCorp subsidiary, with CCUS technology. Two scenarios for permanent CO₂ storage, identified below, were evaluated as potential options to reduce CO₂ emissions. In both scenarios it was assumed all of the flue gas from the units was treated to capture 90% of the CO₂ in the exhaust stream:

- CO₂ Sale to EOR (Scenario A): In this scenario, the CO₂ captured from each power plant is sold for use in EOR to the maximum extent practical, and the remainder of the CO₂ stored in saline aquifers in Wyoming.
- CO₂ Saline Storage (Scenario B): In this scenario, the CO₂ captured from each power plant is exclusively stored in subsurface saline aquifers in Wyoming.

These two scenarios were compared to the Baseline IRP² which included accelerated retirement of units at three of the four coal plants (from 2020 to 2038) considered in the study.

This report evaluated the retrofit costs of applying CCUS technology at these facilities, the availability of EOR and saline storage in the state and associated costs of transportation and storage, the impact on the electricity market in Wyoming and the wider Western Electricity Coordinating Council (WECC) region, the regulatory and political climate for CCUS in Wyoming, and the economic and job impacts of these projects in the state and local areas.

¹ Rocky Mountain Power is a division of PacifiCorp and is a part of Berkshire Hathaway Energy

² Baseline IRP refers to PacifiCorp's 2019 IRP preferred portfolio

Reduction in CO₂ Emissions

The results from this study show that in a diverse portfolio where Rocky Mountain Power's coal units are retrofitted with CCUS³, the (overall) CO₂ emissions are lower than the emissions from the Baseline. The Baseline includes the retirement of coal plants and the installation of new power generation facilities, as the utility must add 2.5 MW per MW that retires to maintain its capacity and energy balance. The need for using uncontrolled natural gas generators as backup for intermittent renewable sources results in higher CO₂ emissions when compared with the CCUS retrofit alternative. For this study, it was assumed that all units would be retrofitted and start operations in 2026 in order to take advantage of 45Q tax credits and match the schedule of changes according to the IRP. The projected CO₂ emissions from Wyoming (through 2038, the last year of the IRP) for the Baseline and portfolio with CCUS retrofits are showed in Figure EX-1.

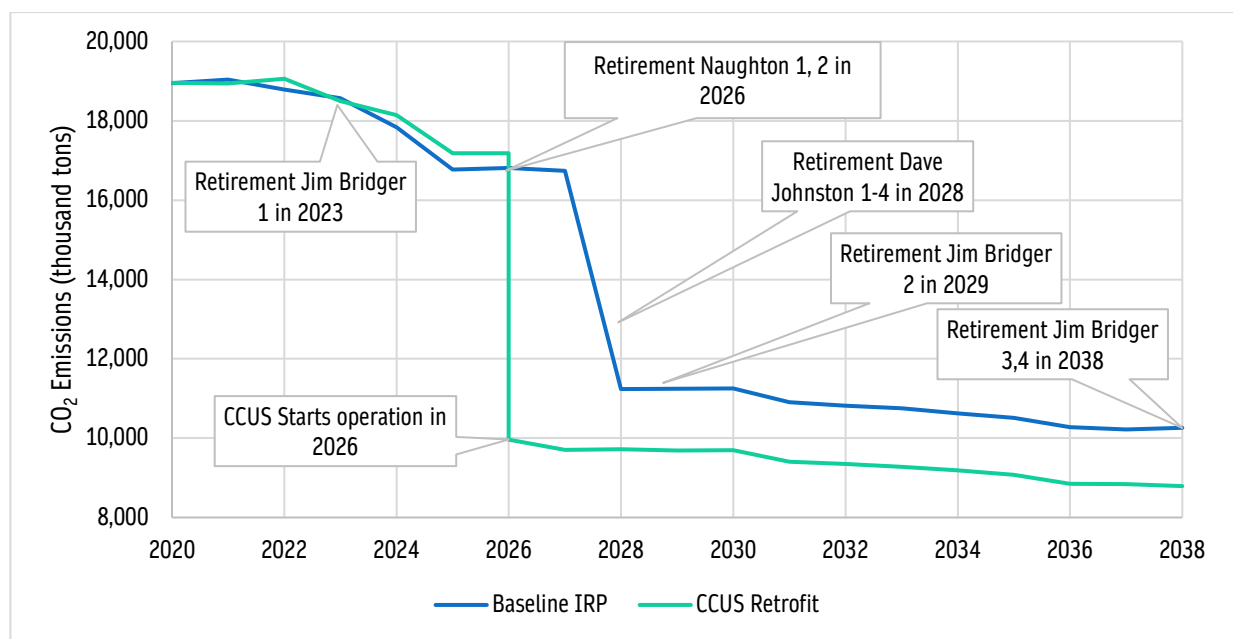


Figure EX-1: Wyoming CO₂ Emissions

Cost of Electricity

A techno-economic analysis (TEA) was completed by LTI to develop the CCUS retrofit costs at the plant facilities. In addition, the University of Wyoming (CEGR and EORI, CEGR) identified the lowest-cost options for transport, storage, and sale of the CO₂ for Scenario A and B. In each scenario, the revenues from Federal Section 45Q tax credits and/or the sale of CO₂ to EOR partly offset the costs to capture, transport and store the CO₂ in the subsurface. Using the cost and revenue data, a net-present value (NPV) analysis was performed to determine the increase or decrease in the cost of electricity (COE) required for the CCUS plant retrofit to break even by offsetting the costs of CO₂ capture, transport and storage.

³ The resource mix in the portfolio with CCUS retrofits and the Baseline is presented in Table 13

The COE calculation does not take into consideration potential sources of revenue which might reduce any effect to the end consumer. The COE increase could be significantly ameliorated by environmental compliance considerations such as participation in a carbon-trade market such as under the California cap and trade market. Additional environmental and social benefits could easily make up for this COE increase. CCUS retrofits are the most favorable at Dave Johnston Units 3&4 and slightly more favorable at Jim Bridger Units 3 and 4 and Naughton Units 1&2 compared to the other units.

Economic Impacts

As part of this study, MISI analyzed the potential job impacts on local economies and the State of Wyoming associated with these projects and the scenarios mentioned above as compared to the Baseline IRP scenario.

In January 2020, the population of Wyoming was 550,000, the labor force totaled 292,800, employment totaled 180,000, unemployment totaled 12,550 and the unemployment rate was 4.3%. The study estimated the direct and indirect job impacts in Wyoming of the CCUS retrofits, assuming that all of the retrofitted units will continue to operate after construction from 2026 through 2055. Figure EX-2 and Figure EX-3 show the results of this analysis for the CCUS scenarios compared to the Baseline IRP scenario.

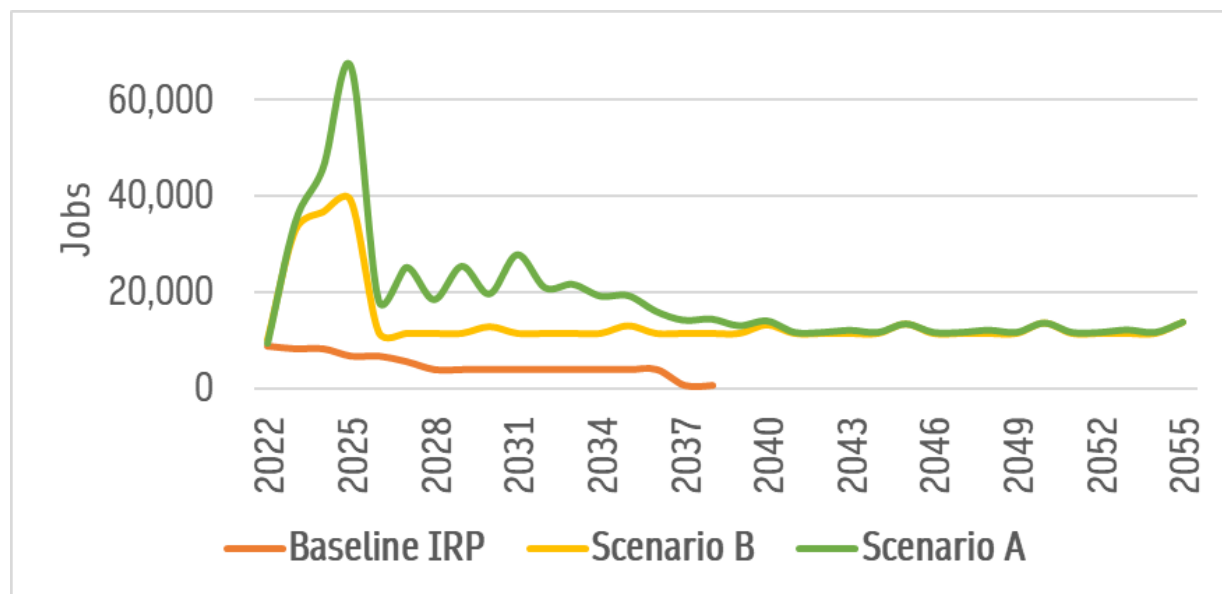


Figure EX-2: Job Impact Analysis by Year

The cumulative Wyoming job impacts analysis illustrates that in the period of 2022 to 2038:

- The Baseline IRP creates about 79,000 jobs;
- Scenario B creates about 272,741 jobs;
- Scenario A creates about 418,137 jobs;

Scenarios A and B create about three to five times as many jobs as the IRP baseline, which projects activities through 2038. Note that further analysis would be required to assess job creation in the Baseline IRP after 2038⁴.

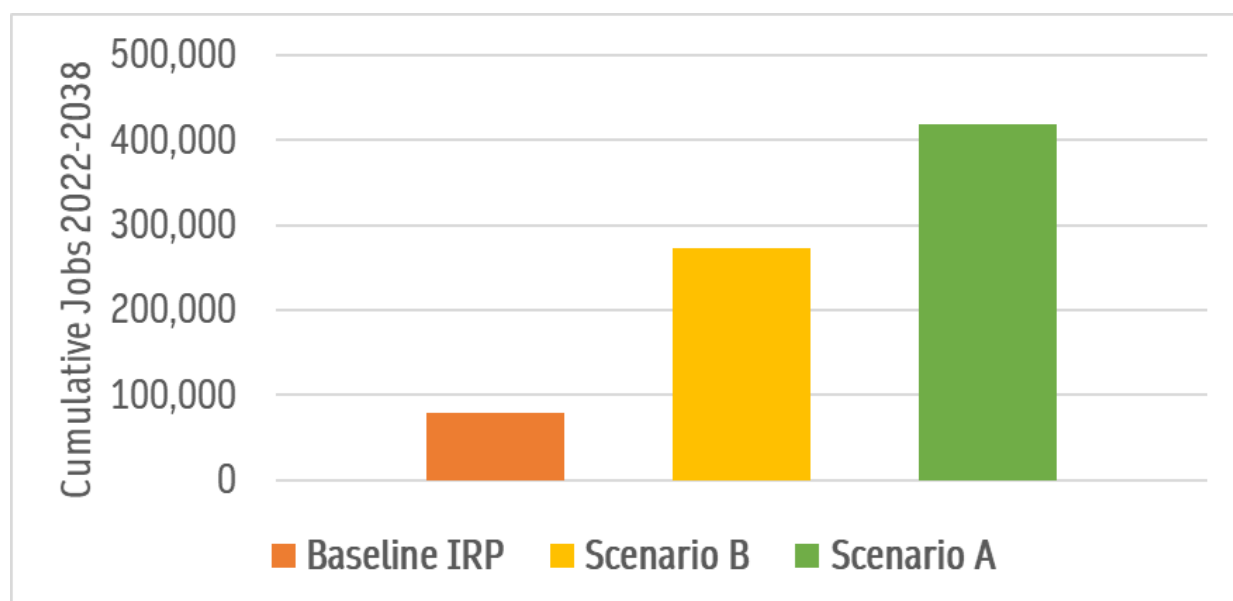


Figure EX-3: Comparative Annual Wyoming Job Impacts

Wyoming Regulatory and Political Climate for CCUS

Coal plays a significant role in the Wyoming economy – and to the economies of Campbell, Converse, Lincoln, and Sweetwater counties. Coal production has been a cornerstone of the modern Wyoming economy since the 1970s, generates 15% of state GDP, and has served as Wyoming’s most stable source of tax revenues and jobs over the past four decades.

Wyoming possesses key geologic formations which are needed to support robust CCUS development. These include reservoirs amenable to CO₂ EOR development and saline formations which could store significant quantities of CO₂ for the foreseeable future. There already exists some infrastructure including CO₂ pipelines, a CO₂-EOR industry, and facilities that are capturing CO₂ (e.g., ExxonMobil’s Shute Creek plant)⁵. In collaboration with federal authorities, the Wyoming Pipeline Corridor Initiative is in the midst of a proceeding to expand rights of ways on federal lands in anticipation of the expansion of the existing pipeline network. In addition, the Wyoming Legislature has recently enacted two laws related to the state’s existing fleet of coal-fired power plants: (1) Senate File 0159 (2019); and (2) House Bill 0200 (2020) that generally promote the retrofit of CCUS.

⁴ Comparison of jobs between the CCUS retrofit and Baseline IRP scenarios will be limited to the 2026 to 2038 time period. However, the jobs created in Scenarios A, B (CCUS retrofit scenarios) will be presented without comparison to the Baseline Scenario.

⁵ <http://www.uwyo.edu/eori/files/docs/wyomings%20miscible%20co2-eor%20potential%20-%20benjamin%20r.%20cook.pdf>.

Figure EX-4 shows the location of the plants evaluated as part of this study, existing pipelines/corridors, and potential CO₂ utilization sites.

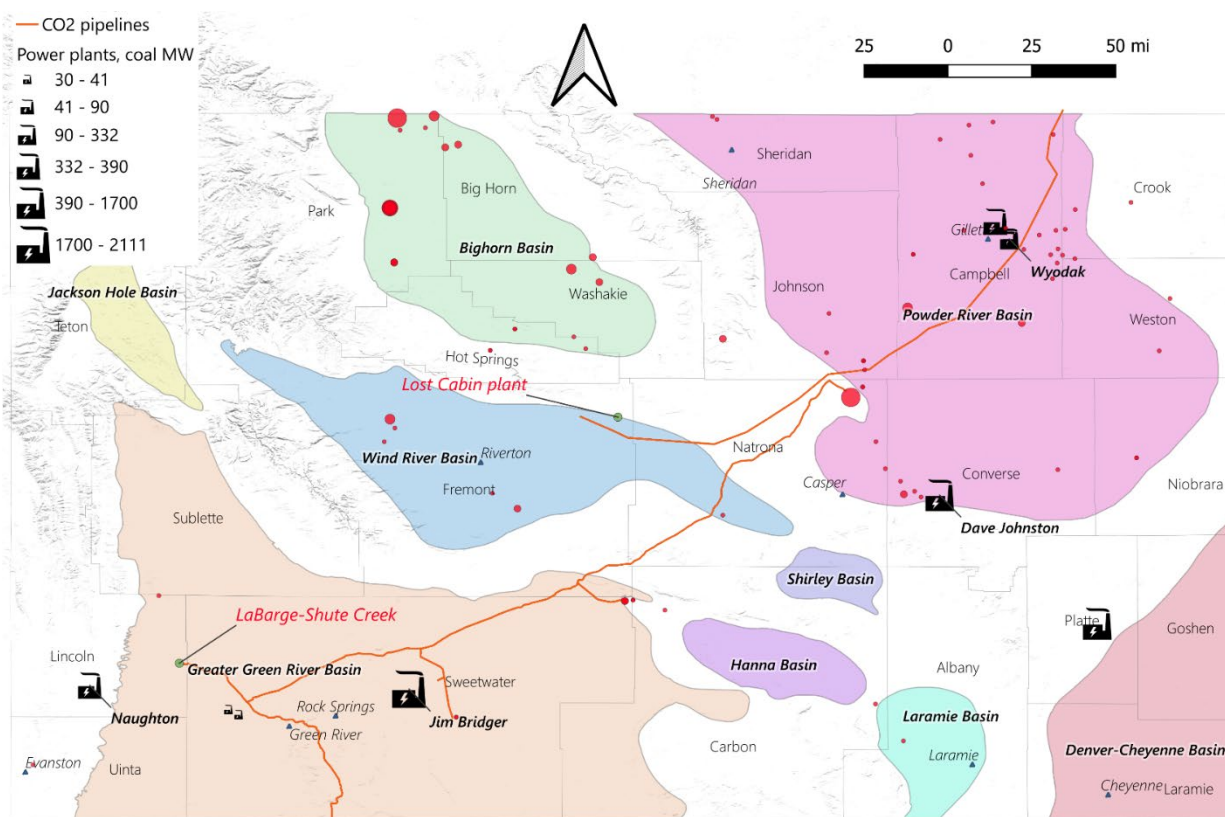


Figure EX-4: Wyoming Plant Locations

Study Conclusions

The study determined that the CCUS retrofit scenarios can achieve greater CO₂ emission reductions when compared to the proposed Integrated Resource Plan (IRP). The CCUS scenario is estimated to reduce CO₂ emissions by 37% more than IRP. The IRP baseline scenario removes 267 million tonnes of CO₂ through the period 2019-2038, at a cost of \$59/ ton (\$53.5/avoided tonne) and the CCUS retrofit scenarios remove 366 million tonnes for the same time period for only \$35/ ton (\$32/avoided tonne), reducing CO₂ emissions by 109 million tons (100 million metric ton) than the IRP preferred scenario.

The two scenarios considered in the study reflect maximum CCUS deployment from PacifiCorp coal power plants in Wyoming. The study's results indicate that one plant (Dave Johnston) would not require additional increase in the cost of electricity. On the other hand, alternative scenarios (considered, but not modeled in the study), which store lower quantities of CO₂, may be more profitable than two scenarios considered. Therefore, the results of this study do not preclude the possibility that other scenarios, with lower deployment of CCUS retrofits to PacifiCorp's Wyoming power plants, could result in lower or no increase in the cost of electricity due to CCUS retrofits.

Furthermore, the dispatch modeling results indicate that the overall incremental system cost in the baseline (preferred IRP) is higher than the incremental cost of electricity in scenario with CCUS retrofits, which leads this report to conclude that CCUS retrofits to PacifiCorp's Wyoming coal-fired power plants can lead to significant environmental and economic benefits.

However, for all but the Dave Johnston Unit 3-4 system, the projects need some sort of additional funding to make the projects financially viable. Such additional funding could be provided by CO₂ compliance payments like allowed participation in California AB32 market.

In addition to the environmental impacts of the project, the CCUS retrofit scenarios create about three times (Scenario B) or five times (Scenario A) as many jobs over the life of the project as the IRP baseline scenario. The IRP accounts for 79,000 jobs through 2038 when it ends.

1 Introduction

Power plants that use coal have provided economic and stable baseload power generation for decades throughout the United States. As some of these plants retire⁶, the economies of the region, state and local communities are impacted. The State of Wyoming approached the Department of Energy (DOE) about conducting an evaluation of carbon capture utilization and storage (CCUS) in Wyoming.

Organizations within the state of Wyoming collaborated with DOE's contractor, Leonardo Technologies Inc. (LTI) and DOE personnel to conduct a technical and economic impacts analysis of retrofitting the Dave Johnston, Jim Bridger, Naughton, and Wyodak power stations in Wyoming with CCUS technologies. In addition, the University of Wyoming's School of Energy Resources' (SER), Center for Economic Geology Research (CEGR), Center for Energy Regulation and Policy Analysis (CERPA) and Enhanced Oil Recovery Institute (EORI) evaluated subsurface storage data for saline aquifers and oilfields and provided estimates for the costs of storing and transporting CO₂ in these geologic formations. Finally, Management Information Services Inc. (MISI) evaluated the local economic impacts of CCUS retrofits to power plants.

1.1 Background

For more than a decade, Wyoming has taken steps to encourage the commercialization and deployment of CCUS within the state since state policymakers have long-recognized the technology's importance to the state's abundant fossil energy resources, the vast majority of which are exported either in the form of primary energy (e.g., coal, natural gas, crude oil) or electricity. According to the U.S. Energy Information Administration (EIA)⁷:

- Wyoming has been the top coal-producing state since 1986, accounting for about 40% of all coal mined in the United States in 2018, and the state holds more than one-third of U.S. coal reserves at producing mines. Mines in Wyoming's Powder River Basin supply subbituminous coal to 113 coal-fired plants in 25 states.
- Wyoming ranks among the top ten states for both the largest natural gas reserves and the highest marketed natural gas production.
- Wyoming was the eighth-largest crude oil-producing state in the nation in 2018, accounting for nearly 3% of U.S. total crude oil output.
- Wyoming produces 15 times more oil, gas, and coal energy than it consumes, and it is the biggest net energy supplier among the states.
- The largest industry in Wyoming is energy-related mining and minerals extraction. Wyoming's large energy producing sector and small population makes the state second in per capita energy consumption and gives it the second most energy-intensive state economy, both after Louisiana.
- Mineral royalties, severance payments and related taxes provide a substantial portion of state revenues. For FY2017, mineral revenue constituted 52.2% of the State of Wyoming's budget.⁸

⁶ <https://www.eia.gov/todayinenergy/detail.php?id=40212>

⁷ <https://www.eia.gov/state/?sid=WY>; <https://www.eia.gov/state/analysis.php?sid=WY>.

⁸ https://www.wyotax.org/_pdfs/2018/Dec/2018-0926-WTA-infographic.pdf.

In 2018, coal-fired power plants produced about 86% of Wyoming's electricity generation.⁹ Wyoming's coal-fired power-plant fleet, consists of a mix of regulated, co-op and independent producers.

Wyoming sends almost three-fifths of the electricity it generates out of state. Within Wyoming, the industrial sector is the largest electricity consumer, and accounts for about three-fifths of the electricity demand in the state. The commercial sector is second and uses just over one-fifth of the state's electricity, while the residential sector accounts for the remaining power demand. One out of five Wyoming households relies on electricity as their primary heating source. In 2018, Wyoming ranked sixth among the states with the lowest average retail electricity price for all sectors.¹⁰

1.1.1 Rocky Mountain Power

In October 2019, PacifiCorp concluded its 2019 integrated resource plan (IRP), the preferred portfolio which included the early retirement of several coal units in Wyoming (see Table 1). Rocky Mountain Power is an electric utility serving Utah, Wyoming and southeastern Idaho and is a subsidiary of PacifiCorp, a Berkshire Hathaway company. PacifiCorp consists of two business units, Pacific Power (which serves Oregon, southeastern Washington, and northern California) and Rocky Mountain Power. PacifiCorp is an owner or partial owner of four coal fueled plants, Dave Johnston, Jim Bridger, Naughton, and Wyodak¹¹ all located in Wyoming¹².

Table 1: Planned Retirement Dates for PacifiCorp Wyoming Coal Plants

Unit	Retirement Date	Notes
Naughton Unit 3	2019	Same as 2017 IRP; converted to natural gas in 2020, not considered in study
Jim Bridger Unit 1	2023	Instead of 2028 in the 2017 IRP
Naughton Units 1-2	2025	Instead of 2029 in the 2017 IRP
Dave Johnston Units 1-4	2027	Same as 2017 IRP
Jim Bridger Unit 2	2028	Instead of 2032 in the 2017 IRP
Jim Bridger Units 3-4	2036	Same as 2017 IRP
Wyodak	2039	Does not retire before 2038

⁹ <https://www.wsgs.wyo.gov/products/wsgs-2012-electricalgeneration-summary.pdf>.

¹⁰ <https://www.eia.gov/state/analysis.php?sid=WY>; EIA Wyoming State Energy Profile, Table 10 (supply and disposition of electricity).

¹¹ <https://www.pacifiCorp.com/energy/thermal.html#:~:text=PacifiCorp%20operates%2017%20thermal%20electric%20facilities%20that%20generate,and%20comply%20with%20all%20state%20and%20federal%20requirements.>

¹² PacifiCorp also operates the plants considered for the study

With respect to CCUS for the existing fleet, the IRP states the following¹³:

- “PacifiCorp continues to monitor CO₂ capture technologies for possible retrofit application on its existing coal-fired resources, as well as their applicability for future fossil fueled plants that could serve as cost-effective alternatives to IGCC plants.”
- “Given the high capital cost of implementing CCS on coal fired generation (either on a retrofit basis or for new resources) CCS is not considered a viable option before 2025. Factors contributing to this position include capital cost risk uncertainty, the availability of commercial sequestration (non-EOR) sites, uncertainty regarding long term liabilities for underground sequestration, and the availability of federal funding to support such projects.”
- “To address the availability of commercial sequestration, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study of carbon capture and storage. These projects were not selected for advance study in Phase II of the grant program.”
- “PacifiCorp issued a request for expression of interest to potential CCUS counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp’s Dave Johnston generating facility for potential enhanced oil recovery (EOR). A phase I feasibility study was received by three interested parties. PacifiCorp remains open to a CCUS FEED study with the three parties if they secure funding in their own efforts.”

In late 2019, the Wyoming Public Service Commission initiated an investigation into the 2019 IRP via an order (Docket No. 90000-147-XI-19) stating: “Given the potential impact on Wyoming customers, it is necessary and desirable that the Commission commence a contested case proceeding, pursuant to the Wyoming Administrative Procedure Act, to allow the Commission and other interested parties to adequately explore all aspects of the 2019 IRP.”¹⁴ That investigation remains open.¹⁵

¹³ https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf at pp. 158-9.

¹⁴ <https://www.wyomingpublicmedia.org/post/investigation-launched-rocky-mountain-powers-integrated-resource-plan#stream/0>.

¹⁵ The PSC’s November 22, 2019 public notice regarding the investigation states in relevant part (see, e.g., <https://pinedaleroundup.com/article/11292019-pinedale-roundup-legal-notices>):

“Pursuant to the Wyoming Administrative Procedure Act and the Wyoming Public Service Commission’s Procedural Rules, notice is hereby given of the investigation pursuant to Wyo. Stat. § 37-2-117 of the Integrated Resource Plan (IRP) filed by Rocky Mountain Power (RMP) on October 18, 2019 (Docket No. 20000-552-EA-19, Record. No. 15192).

“Rocky Mountain Power (RMP) is a public utility subject to the Wyoming Public Service Commission’s jurisdiction pursuant to Wyo. Stat. § 37-2-112.

“On October 18, 2019, RMP filed its IRP pursuant to Commission Rule Chapter 3, Section 33. According to RMP, it developed the IRP using a comprehensive analysis and an extensive public input process resulting in its selection of a least-cost, least-risk preferred portfolio, referred to as Case P-45CNW (Preferred Portfolio). RMP’s Preferred Portfolio includes accelerating retirements of certain coal-fired generation units, primarily located in Wyoming,

1.2 Study Outline and Objectives

The objective of this study was to conduct an evaluation of CCUS and the potential economic benefit from such development for the state of Wyoming. The study was conducted as a team approach with multiple participants contributing. The team was led by DOE-FE staff and included the National Energy Technology Laboratory (NETL), Leonardo Technologies Inc. (LTI), Management Information Services Inc. (MISI), University of Wyoming's School of Energy Resources (SER), Center for Economic Geology Research (CEGR), and Enhanced Oil Recovery Institute (EORI).

Two scenarios were identified and evaluated as potential options which are mutually exclusive of the CCUS retrofit of nine units at the four selected Power Stations in Wyoming. These two scenarios were developed to represent two edges of potential development for CCUS in the State. Relative financial, economic, and job impacts in this report have been prepared based on comparison between these scenarios.

- CO₂ Sale to EOR (Scenario A): In this scenario, the CO₂ captured from each power plant is sold for use in EOR to the maximum extent practical and the remainder of the CO₂ is sent for geologic (saline aquifer) storage in Wyoming.
- CO₂ to Saline Storage (Scenario B): In this scenario, the CO₂ captured from each power plant is sent exclusively for geologic (saline aquifer) storage in Wyoming.

and investment in transmission infrastructure to facilitate the addition of new renewable resources. Through the end of 2023, The Company plans to add 1,821 MW of new solar; 1,989 MW of new wind; and 595 MW of battery storage capacity (Replacement Generation).

"RMP cites economic pressures on existing coal-fired generation units coupled with decreasing costs for new renewable resources as a justification for retirements that exceed 1,457 MW by the end of 2025; 2,874 MW by the end of 2030; and 4,485 MW by the end of 2038. Implementation of the Preferred Portfolio would include the following actions affecting coal-fired generation units located in Wyoming:

1. Conversion of Naughton Unit 3 to a 247 MW natural gas unit in 2020 (coal operations ceased in January 2019);
2. Retirement of Jim Bridger Unit 1 in 2023 (14 years prior to its established depreciable life (EDL));
3. Retirement of Naughton Units 1-2 by 2025 (4 years prior to EDL);
4. Retirement of Dave Johnston Units 1-4 in 2027 (at the end of EDL);
5. Retirement of Jim Bridger Unit 2 by 2028 (9 years prior to EDL); and
6. Retirement of Jim Bridger Units 3-4 by 2037 (at the end of EDL).

"Retirement of coal-fired generation units prior to the end of their EDL may adversely impact the cost and reliability of service provided to RMP's Wyoming customers while producing significant negative economic impacts. These potential impacts, individually and collectively, must be thoroughly evaluated to ensure implementation of the Preferred Portfolio is consistent with the public interest.

"The purpose of this investigation is to allow the Commission and interested parties to explore all aspects of the 2019 IRP, including but not limited to, the methodologies, assumptions and development process resulting in the identification of the Preferred Portfolio."

These two scenarios were compared to a Baseline Scenario which is based upon Rocky Mountain Power's 2017 Integrated Resource Plan (IRP) which included the retirement of all of these units over the next 20 years, with several units' retirements being accelerated from the previous IRP.

LTI conducted a techno-economic analysis (TEA) of the costs associated with retrofitting existing plants with CCUS equipment as well as the costs associated with enhanced oil recovery and saline storage of captured CO₂.

NETL completed a study of market considerations to understand the current and projected market conditions in the Western Electricity Coordinating Council (WECC)—driven by the PacifiCorp IRP preferred portfolio (Baseline Scenario) ¹⁶. This evaluation provides an emphasis on the effects of the Baseline IRP preferred portfolio on reliability in WECC.

The University of Wyoming performed an evaluation of EOR/saline storage opportunities utilizing the SimCCS tool. Los Alamos National Lab (LANL) developed SimCCS as an economic-engineering software tool for making integrated CCUS infrastructure decisions. It uses user-provided regional source, sink, and transportation data, and creates CO₂ pipeline routes and optimizes the network when certain constraints are specified.

MISI performed an economic impact of the scenarios for the areas impacted within Wyoming. This assessed the job impacts on Wyoming and on Campbell, Converse, Lincoln, and Sweetwater counties in the Baseline IRP and Scenarios A and B.

¹⁶ PacifiCorp is a regulated electric utility that has two business units, Pacific Power and Rocky Mountain Power, and also operates the largest transmission system in the Energy Imbalance Market (EIM).

2 State of Wyoming CCUS Policy, Infrastructure, and Geologic Considerations

Wyoming possesses a policy, infrastructure, research, and public acceptance environment that is favorable for the deployment of CCUS technology. As discussed in the previous section, Wyoming's economy is significantly dependent upon the production and sales of fossil fuels, the use of which is subject to a growing number of federal and state mandates limiting the emission of greenhouse gases (GHG) such as carbon dioxide (CO₂). In response, the State of Wyoming has developed a favorable environment within the state for the deployment of CCUS technology by implementing policies which support implementation, building infrastructure, investing in research, and fostering public acceptance.

2.1 Federal CCUS Policy

Wyoming's approach to CCUS is based upon a federal foundation of CCUS law, regulation, and policy. The Federal government supports CCUS and has developed and funded research programs, tax credits, and regulations to enable it.

Under the U.S. Environmental Protection Agency's Clean Air Act (CAA) Affordable Clean Energy (ACE) Rule, for example, existing coal-fired power plants may utilize CCUS for ACE compliance if a state plan so allows.¹⁷ The ACE Rule neither mandates nor prohibits the use of CCUS for the existing coal fleet.¹⁸ Thus, any state -- for ACE Rule compliance reasons -- that wanted to claim GHG reductions via CCUS deployments on the coal-fired power plants within its jurisdiction would need to authorize such an outcome in the plans it files with EPA.¹⁹ The final ACE Rule remains subject to litigation, so the outcome of these considerations is uncertain.

Other portions of the federal regulatory program impacting CCUS were promulgated nearly a decade ago. In December 2010, for example, EPA finalized regulations under the Safe Drinking Water Act's Underground Injection

¹⁷ 84 Fed. Reg. 32520, 32549 (2019) (available at <https://www.govinfo.gov/content/pkg/FR-2019-07-08/pdf/2019-13507.pdf>). State plans under ACE are due July 8, 2022.

¹⁸ The final ACE Rule states (84 Fed. Reg. 32520, at 32547-49) (available at: <https://www.govinfo.gov/content/pkg/FR-2019-07-08/pdf/2019-13507.pdf>):

The EPA ... has concluded that, as proposed, CCS is not the [Best System of Emission Reduction (BSER)] for emissions of CO₂ from existing coal-fired EGUs—nor does it constitute a component of the BSER, as some commenters have suggested ...

Nevertheless, while many commenters argued that CCS should not be considered part of the BSER, they supported its use as a potential compliance option for meeting an individual unit's standard of performance. The EPA agrees with this assessment. Evaluation of the technical feasibility (e.g., space considerations, integration issues, etc.) and the economic viability (e.g., the prospects and availability of long-term contractual arrangements for sale of captured CO₂, the cost of constructing a CO₂ pipeline, the availability of tax credits, etc.) of a CCS project is heavily dependent on source-specific characteristics. Accordingly, state plans may authorize such projects for compliance with this rule.

¹⁹ As to a state's jurisdiction under the ACE Rule, the final regulation states that it applies to "EGUs within [a state's] ... border[] that meet the applicability requirements and are thereby considered a designated facility under ACE." 84 Fed. Reg. at 32558.

Control program governing the injection of CO₂ into geologic formations.²⁰ Relevant aspects of EPA's GHG Reporting Rule were finalized during the same period.²¹ In 2014, EPA finalized a conditional exclusion under the Resource Conservation & Recovery Act for CO₂ streams in geologic sequestration activities.²² The original section 45Q tax credit for carbon oxide sequestration was enacted back in 2008²³; and the Internal Revenue Service (IRS) is in the midst of finalizing implementation guidance for the revised version of that incentive.²⁴

2.2 Wyoming CCUS Policy

For many years Wyoming policymakers have put in place laws, regulations, and policies to encourage the advancement and deployment of CCUS technologies and projects in the state. A decade ago, for example, the Wyoming Legislature – following recommendations by the Interstate Oil & Gas Compact Commission -- enacted a suite of CCUS laws that:

- Specifies who owns the pore space²⁵;
- Establishes permitting procedures and requirements for CCUS sites, including permits for time-limited research²⁶;
- Provides a mechanism for post-closure MRV via a trust fund approach²⁷;
- Provides a mechanism for unitization of storage interests²⁸;
- Specifies that the injector, not the owner of pore space, is generally liable²⁹;
- Clarifies that vis-à-vis storage rights, production rights are dominant but cannot interfere with storage; and
- Provides a certification procedure for CO₂ incidentally stored during EOR³⁰.

²⁰ 75 Fed. Reg. 77230 (2010) (available at <https://www.govinfo.gov/content/pkg/FR-2010-12-10/pdf/2010-29954.pdf>).

²¹ Subpart PP (Suppliers of Carbon Dioxide) was finalized in 2009 (74 Fed. Reg. 56373 (available at <https://www.epa.gov/sites/production/files/2015-06/documents/ghg-mrr-finalrule.pdf>)); subparts RR (Geologic Sequestration of Carbon Dioxide) and UU (Injection of Carbon Dioxide) were finalized in 2010 (75 Fed. Reg. 75060 (available at <https://www.govinfo.gov/content/pkg/FR-2010-12-01/pdf/2010-29934.pdf>)).

²² 79 Fed. Reg. 350 (2014) (available at <https://www.govinfo.gov/content/pkg/FR-2014-01-03/pdf/2013-31246.pdf>).

²³ 26 U.S.C. § 45Q (2019) (available at <https://www.law.cornell.edu/uscode/text/26/45Q>).

²⁴ On February 19, 2020, the IRS published two guidance items concerning amended § 45Q: Notice 2020-12 and Revenue Procedure 2020-12. On June 2, 2020, the IRS proposed additional implementation regulations regarding amended § 45Q: 85 Fed. Reg. 34050 (available at <https://www.federalregister.gov/documents/2020/06/02/2020-11907/credit-for-carbon-oxide-sequestration>). The comment period on that notice of proposed rulemaking closed on August 3, 2020.

²⁵ Wyo. Stat. § 34-1-152 (2019).

²⁶ Id. § 35-11-313.

²⁷ Id. § 35-11-318.

²⁸ Id. § 35-11-315.

²⁹ Id. § 34-1-513.

³⁰ Id. § 30-5-502.

The Wyoming Department of Environmental Quality (DEQ) is currently seeking primacy for the UIC Class VI program. On April 14, 2020, EPA proposed to approve DEQ's application, with a final decision expected later this year.³¹

Several Wyoming state agencies have as part of their missions the advancement of CCUS. These include the School of Energy Resources (SER) at the University of Wyoming (UW), the Enhanced Oil Recovery Institute, and the Wyoming Infrastructure Authority.

2.3 Wyoming Laws Impacting CCUS Retrofits

The Wyoming Legislature has recently enacted two laws related to the state's existing fleet of coal-fired power plants: (1) Senate File 0159 (2019); and (2) House Bill 0200 (2020).

2.3.1 Senate File 0159 (2019)

On March 8, 2019, Wyoming Senate File (SF) 0159 was passed into law. SF 0159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility and requires the purchase of electricity generated from an acquired retiring coal fired electric generation facility.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission (PSC) unless the PSC has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the PSC determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 0159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the PSC, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the PSC approves a one hundred percent cost recovery in rates for the cost of the power purchase agreement and the agreement is one hundred percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

2.3.2 House Bill 0200 (2020).

On March 24, 2020, Governor Gordon signed House Bill (HB) 0200 into law. The bill requires the PSC to "establish by rule energy portfolio standards that will maximize the use of dispatchable and reliable low-carbon electricity."³² "Low-carbon" is defined as "electricity that is generated using carbon capture, utilization and storage technology that produces carbon emissions not greater than six hundred fifty (650) pounds of carbon dioxide per megawatt hour of generated electricity averaged over one (1) calendar year."³³ "Carbon capture, utilization and storage

³¹ 85 Fed. Reg. 20621 (2020) (available at <https://www.govinfo.gov/content/pkg/FR-2020-04-14/pdf/2020-07223.pdf>). The comment period closes May 29, 2020.

³² HB 0200 § 37-18-102 (2020).

³³ Id. § 37-18-101(a)(iii).

technology" means "technology that has the principal purpose of capturing, reusing, storing, sequestering or using carbon dioxide emissions to prevent carbon dioxide from entering the atmosphere whether constructed integral or adjacent to a coal fired generation facility."³⁴ The "integral or adjacent" language suggests that CCUS retrofits qualify.

"Dispatchable" is defined as "a source of electricity that is available for use on demand and that can be dispatched upon request of a power grid operator or that can have its power output adjusted, according to market needs."³⁵ Dispatchable presumably does not include wind and solar power. Coal plants, on the other hand, are dispatchable. There are no nuclear plants in Wyoming.

"Reliable" means "generated electricity that is not subject to intermittent availability."³⁶ By this definition, wind and solar power presumably are not "reliable."

The ultimate standards are to take effect no later than July 1, 2030. They must require that a specified percentage of electricity generation satisfy the low-carbon requirements. Intermediate requirements -- i.e., prior to July 1, 2030 -- must also be set.

These standards only apply to power companies regulated by the PSC. They do not apply, on the other hand, to cooperatives. The PSC currently is in the midst of a proceeding that examines the proposed retirements of certain coal plants in Wyoming.

The standards require the establishment of a baseline founded on reliability. Specifically, each utility regulated by the PSC must ensure that "new or expanded intermittent generation resources do not unreasonably diminish power quality or increase momentary outages across a utility's service territory or in any particular location."³⁷

Each regulated utility also must: (1) "monitor and report electric reliability and power quality outcomes" in integrated resource plans, or "as otherwise directed by the [PSC]"³⁸; and (2) "[r]equire the utility to take any steps the [PSC] deems reasonably necessary to maintain reasonable levels of electric reliability and power quality."³⁹

HB 0200 builds upon the limit on cost recovery that the Wyoming Legislature enacted in 2019 in SF 0159, discussed above. Going beyond the requirement that a utility try to sell a coal plant, HB 0200 further limits or prohibits rate recovery unless the PSC has determined that the utility also is achieving the new low-carbon standards.

HB 0200 allows a regulated utility to seek rate recovery for CCUS, including a higher return on equity, if the CCUS is "integral or adjacent to a coal fired generation facility in Wyoming."⁴⁰ Rate recovery is capped at 2% of each customer's bill.⁴¹ If CCUS costs exceed that 2% cap, the PSC is authorized to "take such actions as necessary ... to

³⁴ *Id.* § 37-18-101(a)(i).

³⁵ *Id.* § 37-18-101(a)(ii).

³⁶ *Id.* § 37-18-101(a)(iv).

³⁷ *Id.* § 37-18-102(a)(v)(A).

³⁸ *Id.* § 37-18-102(a)(v)(B).

³⁹ *Id.* § 37-18-102(a)(v)(C).

⁴⁰ *Id.* § 37-18-102(c)(i).

⁴¹ *Id.* 37-18-102(c)(iii).

ensure the public utility is able to recover its prudently incurred incremental costs and customers are not charged for those incremental costs."⁴²

HB 0200 additionally allows the regulated utility to recognize sales of CO₂ for EOR and other utilizations. The bill provides that⁴³:

"... a public utility may apply to the commission for authorization to allow a portion of any revenues from the sale of carbon dioxide captured, stored or utilized as a result of generating dispatchable and reliable low-carbon electricity to be returned to the shareholders of the public utility."

Finally, the standards must consider "any potentially expiring federal tax credits." There are several potential federal tax credits that apply to CCUS, including section 45Q.

2.4 CCUS Infrastructure in Wyoming

Wyoming possesses key geologic formations which are needed to support robust CCUS development. These include reservoirs amenable to CO₂ EOR development and saline formations which could store significant quantities of CO₂ for the foreseeable future. There already exists some infrastructure including CO₂ pipelines, a CO₂-EOR industry, and facilities that are capturing CO₂ (e.g., ExxonMobil's Shute Creek plant).⁴⁴ In collaboration with federal authorities, the Wyoming Pipeline Corridor Initiative is in the midst of a proceeding to expand rights of ways on federal lands in anticipation of the expansion of the existing pipeline network.⁴⁵

Several deep geologic rock formations have been and continue to be studied for their suitability in permanently storing CO₂. These include CO₂ storage zones and cap rocks, which seal the storage zone and keep the CO₂ contained. Potential storage zones being investigated are deep sandstone layers including the Muddy, Lakota, and Fall River (Dakota Group), Lower Sundance, and Minnelusa Formations. These formations are overlain by thousands of feet of impermeable rock, which would ensure permanent containment of fluids within the potential storage zones.

Pioneering research on characterizing the two potential CO₂ storage reservoirs (Weber Sandstone, and Madison Limestone), both deep-saline aquifers on the Rock Springs uplift (RSU) in southwestern Wyoming was performed in the past five years. The project - known as the Wyoming Carbon Underground Storage Project or WY-CUSP produced a detailed site characterization of the two deep saline aquifers on the RSU for potential pilot and commercial-scale CO₂ storage. Detailed data from the project provided baseline assessments that could directly support future industrial CCUS operations in the region. In addition, the WY-CUSP team designed a strategy to treat the saline water displaced from the target storage reservoirs by injected CO₂.

⁴² Id.

⁴³ Id. § 37-18-102(c)(ii).

⁴⁴ http://www.uwyo.edu/eori/_files/docs/wyomings%20miscible%20co2-eor%20potential%20-%20benjamin%20r.%20cook.pdf.

⁴⁵ <https://eplanning.blm.gov/epl-front-office/eplanning/planAndProjectSite.do?methodName=renderDefaultPlanOrProjectSite&projectId=1502028>.

2.4.1 Public Acceptance

Public acceptance of CCUS has been identified statewide according to a recent survey of Wyoming residents' values and beliefs related to energy. The survey found that CCUS was supported by 35.4% of respondents, with 55.8% “neutral or not sure” (*see* Figure 1). Only 8.8% of respondents opposed the technology.

Support and opposition for Wyoming's energy technologies and production

Percentage of Wyoming residents who support or oppose types of energy technologies and production in Wyoming

Support
Oppose
Neutral or not sure

Percentages may not total 100 due to rounding.

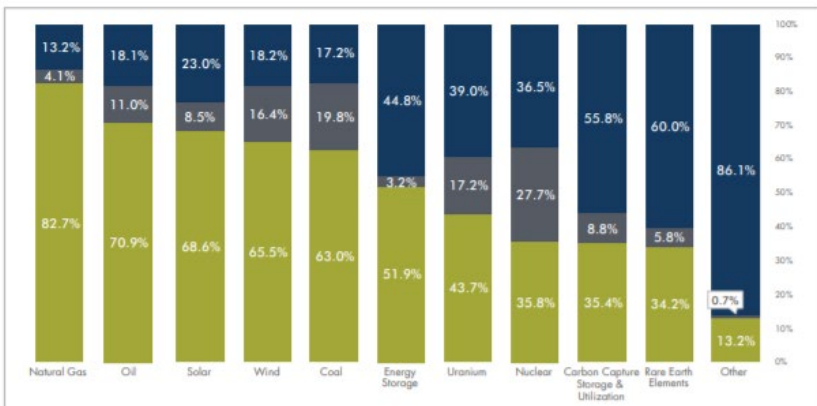


Figure 1: Survey Summary – Wyoming's Energy Future⁴⁶

Public acceptance of CCUS is even higher in specific communities. Gillette and Campbell county, for example, appropriately deem themselves to be the “Energy Capital of the World” and currently are positioning themselves as “Carbon Valley,” reflecting a commitment to low-carbon technologies such as CCUS.

2.4.2 Out-of-State Markets and Low-Carbon Emission Standards

As noted above, Wyoming sends almost three-fifths of the electricity it generates out of state. Thus, a Wyoming-based coal-fired power plant selling electricity must pay attention to the low-carbon emission standards and related low-carbon requirements in those other jurisdictions. A growing number of those jurisdictions, as well as utilities operating within them, have adopted a variety of low-carbon goals or requirements (*see* Figure 2).

For example, California, Oregon, and Washington have enacted greenhouse gas (GHG) emission performance standards (EPS) applicable to electricity generated in state or delivered to the state from out-of-state generating units. The emission performance standards are set at the level of a state-of-the-art combined cycle natural gas facility. The California and Oregon EPS are 1,100 lb. CO₂/MWh; the Washington EPS is 925 lb. CO₂/MWh.

These EPS for electricity generation are in addition to a plethora of separate low-carbon policies that a growing number of states throughout the United States are adopting that also impact the export of primary and produced energy from Wyoming. These policies include cap-and-trade programs; mid-century (or earlier) GHG reduction goals or requirements; and renewable/clean energy portfolio standards.

⁴⁶ http://www.uwyo.edu/haub/_files/_docs/research/2020-energy-survey-two-page-summary.pdf. The survey was conducted jointly by UW's SER and the Ruckelshaus Institute in fall 2019 and winter 2020. The survey was sent to 3100 randomly sampled addresses in Wyoming, with 522 responses. The margin of error was +/- 4.3%.

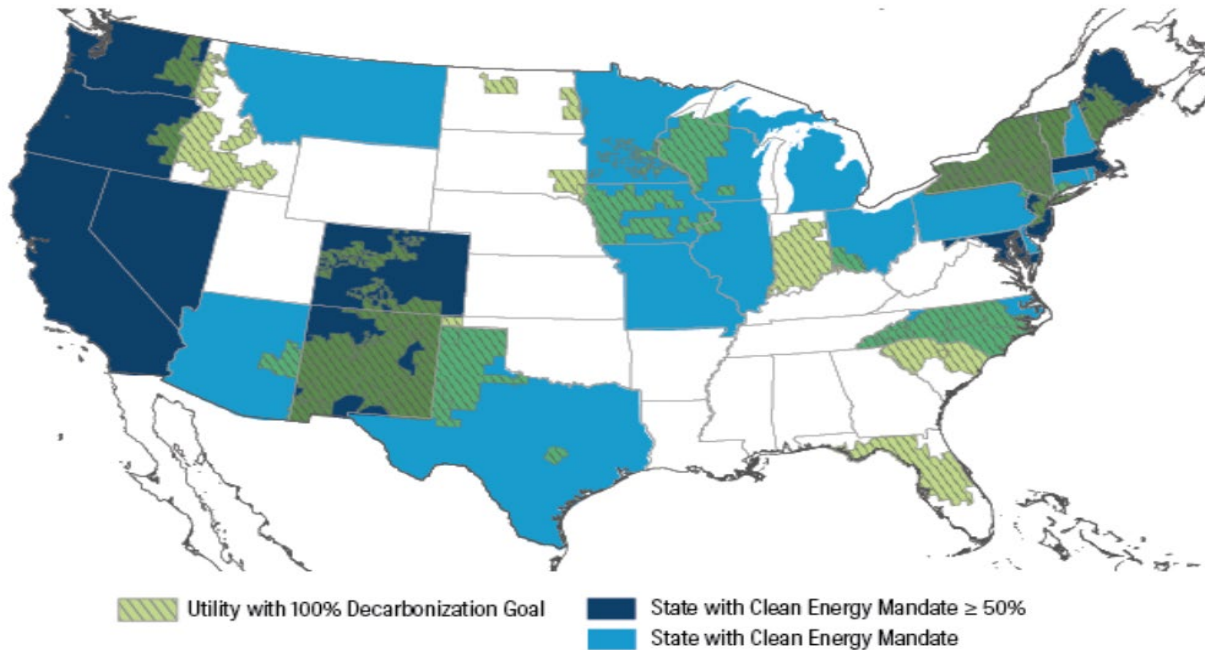


Figure 2: States and Utilities with Decarbonization/Clean Energy Mandates/Goals⁴⁷

An initial consideration is whether CCUS-based electricity generated and exported from an existing Wyoming-based coal-fired power plant satisfies federal and state law.

Under federal law, the final ACE Rule – which remains subject to litigation -- neither mandates nor prohibits the use of CCUS for the existing coal fleet. EPA stated that “state plans may authorize [CCUS] projects for compliance with [the ACE Rule].”⁴⁸ Thus, as an initial matter, the Wyoming ACE plan – due July 8, 2022 – would need to authorize CCUS as a means of compliance.

Under the laws of the states receiving CCUS-based electricity generated in Wyoming, the following two considerations come into play. First, does the electricity satisfy the relevant EPS both in terms of CO₂ emission rate at the stack, and geologic storage standards? And second, does the electricity satisfy all other low-carbon state policies that might apply? Although these issues remain in play, early indications suggest that CCUS-based electricity generated in Wyoming should satisfy applicable state law requirements. California and the State of Washington stand as examples.

California. California’s Emission Performance Standard⁴⁹ explicitly allows geologic sequestration to be utilized. In terms of assessing the standards for “sequestration,” as a conservative case the

⁴⁷ <https://twitter.com/WRIEnergy/status/1212811068457848834/photo/1>.

⁴⁸ 84 Fed. Reg. at 32549.

⁴⁹ https://ww2.energy.ca.gov/emission_standards/regulations/Chapter11_Article1_SB1368_Regulations.PDF.

economics of utilizing California's new CCS/CCUS methodology could also be considered.⁵⁰ Although California's new CCS methodology currently only applies to transportation fuels under the Low Carbon Fuel Standard.

State of Washington. The situation in the State of Washington is similar. Washington's new law requires the elimination of "coal-fired resources" on or before December 31, 2025.⁵¹ However, the definition of "coal-fired resource" excludes a "generating facility that is subject to an obligation to meet the standards contained in RCW 80.80.040(3)(c)".⁵² It specifically excludes certain emissions when assessing compliance with applicable GHG emission standards from baseload power plants. Excluded are emissions that: (1) are injected permanently in geological formations; (2) are permanently sequestered by other means approved by the department; and (3) are sequestered or mitigated as approved under specified plans. Stated another way, by separate statute, the State of Washington – more than a decade ago– provided a pathway for CCUS to be used for compliance. In enacting the 2025 coal phase-out, the Washington Legislature reaffirmed the applicability of that law. So, the 2025 coal-ban likely applies to power plants that are not equipped with CCUS technologies as specified by and approved under RCW 80.80.040(3)(c).

⁵⁰ <https://ww2.arb.ca.gov/resources/documents/carbon-capture-and-sequestration-protocol-under-low-carbon-fuel-standard>.

⁵¹ Sec. 3 of the law, available here: <http://lawfilesexternal.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5116-S2.SL.pdf>.

⁵² Sec. 7(b)(ii), available here: <http://lawfilesexternal.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5116-S2.SL.pdf>. RCW 80.80.040(3)(c), in turn, is here: <https://app.leg.wa.gov/RCW/default.aspx?cite=80.80.040>.

3 Regional CO₂ Markets, Pipeline, and Storage Opportunities

3.1 Current CO₂ Market

Currently two gas processing plants (Shute Creek and Lost Cabin gas plants) in Wyoming separate CO₂ from natural gas and sell the CO₂⁵³ (see Figure 5). CO₂ is separated from natural gas using chemical or physical solvents and is dehydrated and compressed for sale to customers. The Shute Creek gas plant is owned by Exxon Mobil, whereas the Lost Cabin gas plant is owned by ConocoPhillips. The Shute Creek gas plant supplies CO₂ to several customers, including CO₂ for EOR in Chevron's Rangely oilfield in Colorado, Fleur de Lis Energy's Salt Creek oilfield, Devon's Big Sand Draw oilfield, Denbury's Grieve oilfield in Wyoming, and its Bell Creek oilfield in Montana. In contrast, the Lost Cabin gas plant only supplies CO₂ to Denbury's Greencore pipeline for EOR in the Bell Creek oilfield in Montana. In addition to operating CO₂ floods, Denbury also owns a major share of the CO₂ used in their EOR projects: in 2012, they purchased an overriding royalty interest (ORRI) of 1.2 trillion cubic feet (Tcf) in proven CO₂ reserves in the LaBarge platform supplying gas to the Shute Creek gas plant⁵⁴. Denbury pays ExxonMobil a fee to gather and process the CO₂. In addition to their existing CO₂ floods, Denbury planned to build a pipeline to transport CO₂ from Wyoming to the oilfields in the Cedar Creek anticline (CCA) geologic structure on the Montana-North Dakota border. They planned to develop an EOR project within the CCA by extending their existing Greencore pipeline from its current terminus at the Bell Creek oilfield in Montana by 110 miles. The pipeline connect was originally expected to be completed by the end of this year⁵⁵. However, this and other current Denbury CO₂-EOR projects could be impacted by their Chapter 11 filing for bankruptcy on July 30, 2020.

In May 2020, ExxonMobil was granted a permit to construct and operate the LaBarge Carbon Capture Project, which consists of additions to the Shute Creek gas plant, a CO₂ disposal (injection) well, and the construction of a nine-mile long CO₂ pipeline⁵⁶. ExxonMobil plans to operate a carbon capture, sales, and disposal project storing CO₂ produced from natural gas in the subsurface. The project is expected to cost over \$260 MM⁵⁷. At the time of this report's preparation, the annual quantity of CO₂ to be stored in ExxonMobil's proposed CO₂ disposal project is unknown.

The average quantity of CO₂ sold by gas processing plants in Wyoming (Shute Creek, Lost Cabin) to third parties for CO₂-EOR and non-EOR uses is shown in Figure 3. Annual CO₂ sales in 2015 were 378 MMcf/d in 2015. More recently, average sales of CO₂ from the two natural gas processing plants in Wyoming were around 280 to 360 MMcf/d. A portion of this CO₂ is used for EOR inside and outside Wyoming.

⁵³ The economic value from sale of byproduct helium, which also occurs with CO₂ in natural gas, is quite attractive

⁵⁴ <http://www.sec.gov/Archives/edgar/data/945764/000094576416000092/dnr-20151231x10k.htm>,
<http://www.sec.gov/Archives/edgar/data/945764/000094576412000091/exhibit21.htm>

⁵⁵ Denbury website, and Q1 earnings call: <https://www.denbury.com/investor-relations/investor-presentations-and-webcasts/default.aspx>

⁵⁶ See Wyoming Industrial Development Information and Siting Act Section 109 Permit Application LaBarge Carbon Capture Project Kemmerer, Wyoming, and <http://deq.wyoming.gov/isd/application-permits/resources/labarge-carbon-capture-project/>

⁵⁷ http://deq.wyoming.gov/media/attachments/Industrial%20Siting/Application%20and%20Permits/LaBarge%20Carbon%20Capture%20Project/2020%200113_ISD_Exxon%20Mobil%20Corp_Application_19-06.pdf

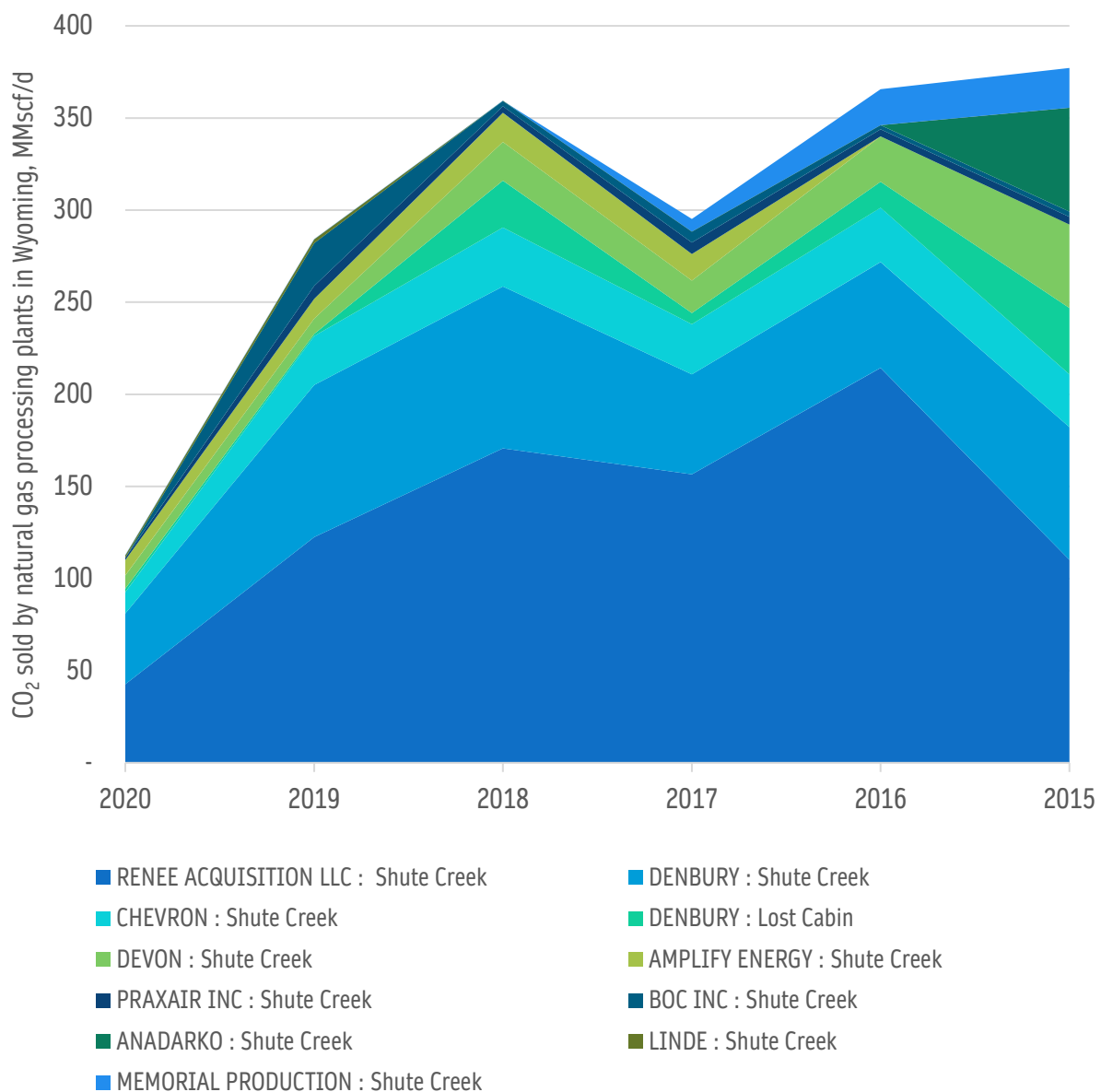


Figure 3: Wyoming CO₂ Sales for Natural Gas Processing⁵⁸

Currently, CO₂ is being injected in 7 oilfields in Wyoming (*see* Table 2). Fields suitable for CO₂-EOR are shown as red circles and are categorized by the quantity of crude oil remaining-oil-in-place (larger circles indicate more oil potential for oil production). The largest injections are in the Salt Creek, Patrick Draw, Beaver Creek, Big Sand Draw, and Grieve oilfields.

⁵⁸ Data from Wyoming Oil & Gas Conservation Commission (WOGCC), 2020-2010. Legend - Natural Gas Processing Company: Source.

Table 2: CO₂ Sold in Wyoming and Montana.⁵⁹

Oilfield Operator	Oilfields	CO ₂ Sales Volume MMscf/d (MMT/y)			CO ₂ Injected in Wyoming MMscf/d		
		2019	2018	2017	2019	2018	2017
Fleur de Lis Energy	Salt Creek Patrick Draw WC	122.6 (2.3)	170.6 (3.2)	156.6 (3)	860	1,056	1,052
Devon	Big Sand Draw Beaver Creek	8.2 (0.2)	21 (0.4)	17.6 (0.3)	72.4	108.1	97.7
Denbury	Grieve Bell Creek (MT)	83.6 (1.6)	113.4 (2.1)	60.4 (1.1)	26.4	24.0	14.2
Amplify Operating Energy LLC	Wertz Lost Soldier	10.9 (0.2)	15.8 (0.3)	14.4 (0.3)	0.0	0.1	-
Chevron	Rangely (CO)	26.7 (0.5)	32 (0.6)	27.2 (0.5)	-	-	-
Non-EOR	-	-	6.5 (0.1)	12.2 (0.2)	-	-	-

Among the oilfields in Table 2, Denbury currently injects CO₂ in the Salt Creek and Grieve oilfields. They also inject CO₂ in the Bell Creek oilfield at the WY-MT border, and the CO₂ for these Denbury operations is transported from Shute Creek/La Barge gas plant and the Lost Cabin gas plant. In total, Denbury used 113 MMcf/d CO₂ last year. Denbury purchased the royalty interest rights for 1.2 TCF CO₂ in 2012 (they can be supplied up to 115 MMcf/d from Shute Creek by 2021, and are currently using approximately 88 MMcf/d. Similarly, Denbury can source approximately 25 MMcf/d additional CO₂ from the existing Lost Cabin gas plant contract). Moreover, in 2018, the Shute Creek and the Lost Cabin gas plants emitted 1.2 MMT CO₂/y and 0.14 MMT CO₂/y, respectively. The upper bound on the additional quantity of CO₂ that can be supplied for EOR is ~1.4 to 2 MMT CO₂/y⁶⁰, significantly lower than the potential demand for CO₂ from oilfields that are not currently undergoing EOR in Wyoming.

3.2 Pipeline Infrastructure

Existing pipeline networks for oil, condensate, and gas in Wyoming are extensive and can be viewed through the Wyoming Reservoir Information Tool (WyRIT) available at <https://eori.wygisc.org/>. Primary CO₂ trunklines in

⁵⁹ Data from Wyoming Oil & Gas Conservation Commission (WOGCC).

⁶⁰ Expansion of capacity at Shute Creek would depend on natural gas prices, helium prices, and the capability of existing gas processing trains and is outside the scope of this report. Similarly, Lost Cabin is another smaller source.

Wyoming are shown in Figure 4 and Figure 5. Existing built and operating CO₂ pipeline networks are more limited, but significant when compared to other states. The primary CO₂ pipeline is the 232-mile Greencore Pipeline operated by Denbury resources, and often referred to as the Denbury Pipeline. This pipeline, which has allowed "played-out" fields to perform significant tertiary oil recovery using CO₂-EOR, was actively serving five injection sites in Wyoming as of July 2019. Much of the CO₂ carried on this pipeline crosses the state border to serve Montana's CO₂-EOR needs at the Bell Creek Field. The Denbury pipeline was credited with significant labor income, job-creation, and gross state domestic product⁶¹. This work followed the assumption that any use of the Denbury pipeline would require Denbury's consent. Accordingly, the analysis in this work excludes the potential use of the Denbury pipeline and has removed from consideration oilfield-formations currently being served by CO₂ transported on Denbury's pipeline. The Wyoming Pipeline Corridor Initiative (WPCI) was designed in 2012 to pre-permit 1914 miles of corridors in Wyoming for future pipelines carrying oil, natural gas, CO₂, and other substances⁶². The WPCI corridors (see Figure 4) are intended to expedite construction and provide regulatory stability.

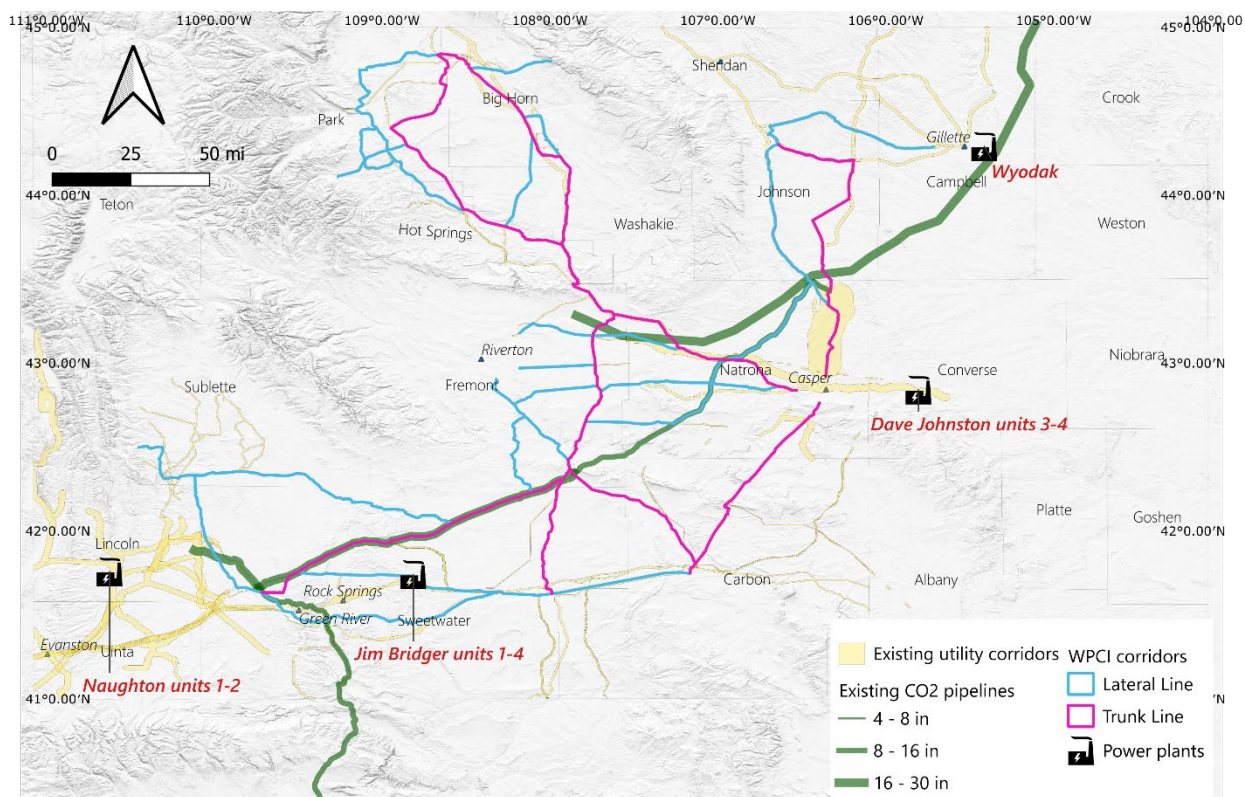


Figure 4: Wyoming Pipeline Infrastructure⁶³

⁶¹ Cook, B. R. 2013. Wyoming's miscible CO₂ enhanced oil recovery potential from main pay zones: an economic scoping study. Enhanced Oil Recovery Institute, School of Energy Resources, University of Wyoming.

⁶² Wyoming Pipeline Corridor Initiative, 2019. State of Wyoming Proposal. Wyoming Pipeline Authority, State of Wyoming. July, 2019.

⁶³ Data from EIA, BLM, and Energy Velocity. Note: Labels in italics denote population centers, other unitalicized labels are county names. Pink lines indicate proposed trunk line corridors, blue lines indicate proposed lateral pipeline corridors, green lines represent existing CO₂ pipelines and light yellow lines represent existing state-wide utility corridors in Wyoming.

Figure 4 shows that the power plants considered in this study are located near existing utility corridors, and/or located near the proposed WPCI corridors. For example, the Naughton and Dave Johnston power plants are located near existing utility corridors, the Jim Bridger plant is located near a proposed WPCI lateral line, and the Wyodak plant is located very close to an existing CO₂ pipeline and also existing utility corridors and proposed WPCI lateral pipelines.

The main Wyoming body responsible for implementing the WPCI is the Wyoming Energy Authority (WEA). Although many corridors now contain pipelines, this regulatory support is not dependent on an extant pipeline along the indicated route. Of the 1,914 miles of proposed pipeline corridors, 1,105 miles are on (Federal) Bureau of Land Management (BLM)-managed lands, and the state of Wyoming submitted a proposal to the BLM Wyoming State Office for the pipeline corridor designation in 2019. The WPCI would not authorize any new infrastructure projects or rights-of-way (ROWs), it would amend several resource management plans across the state. A draft environmental impact statement (EIS) was issued in July 2020, and the final record of decision is due by November 2020⁶⁴.

3.3 CO₂ Storage Options, EOR Opportunities

Sedimentary basins are regions of the Earth formed by the accumulation and gradual deposition of sediments. These sedimentary basins may contain pore spaces suitable for saline aquifer storage of CO₂ and/or CO₂-EOR. The sedimentary basins of Wyoming are shown in Figure 5. The feasibility of storing CO₂ in saline aquifers or oil reservoirs in sedimentary basins of Wyoming has been studied extensively⁶⁵. The results of these studies are summarized in Table 3.

Successful storage of CO₂ in saline aquifers requires the following:

- The CO₂ must be pumped deep enough into the subsurface that it becomes dense and makes efficient use of the available space,
- The buoyant CO₂ must be contained laterally and vertically so that it does not seep back to the surface, and,
- The rock formation the CO₂ is pumped into must not contain valuable fresh drinking-water.

In this study UWy curated a set of saline formations in Wyoming's Basins meeting these criteria. The pipeline network simulations in this work favored locations in Wyoming's Powder River Basin (PRB) and Rock Springs Uplift (RSU), which is a part of the Greater Green River Basin (Figure 5). An overview of sedimentary basins of Wyoming is provided initially in this section. Thereafter, the discussion is devoted to the RSU and the PRB geologic storage structures.

⁶⁴ See: https://eplanning.blm.gov/public_projects/lup/1502028/20018694/250024780/Final_DEIS_PowerPoint_Virtual_Public_Meetings.pdf

⁶⁵ Lynds, R.M., 2013. Geologic storage assessment of carbon dioxide (CO₂) in the Laramie basins of Wyoming, Technical Memorandum No. 3, prepared for the Wyoming Department of Environmental Quality, Laramie, Wyoming.

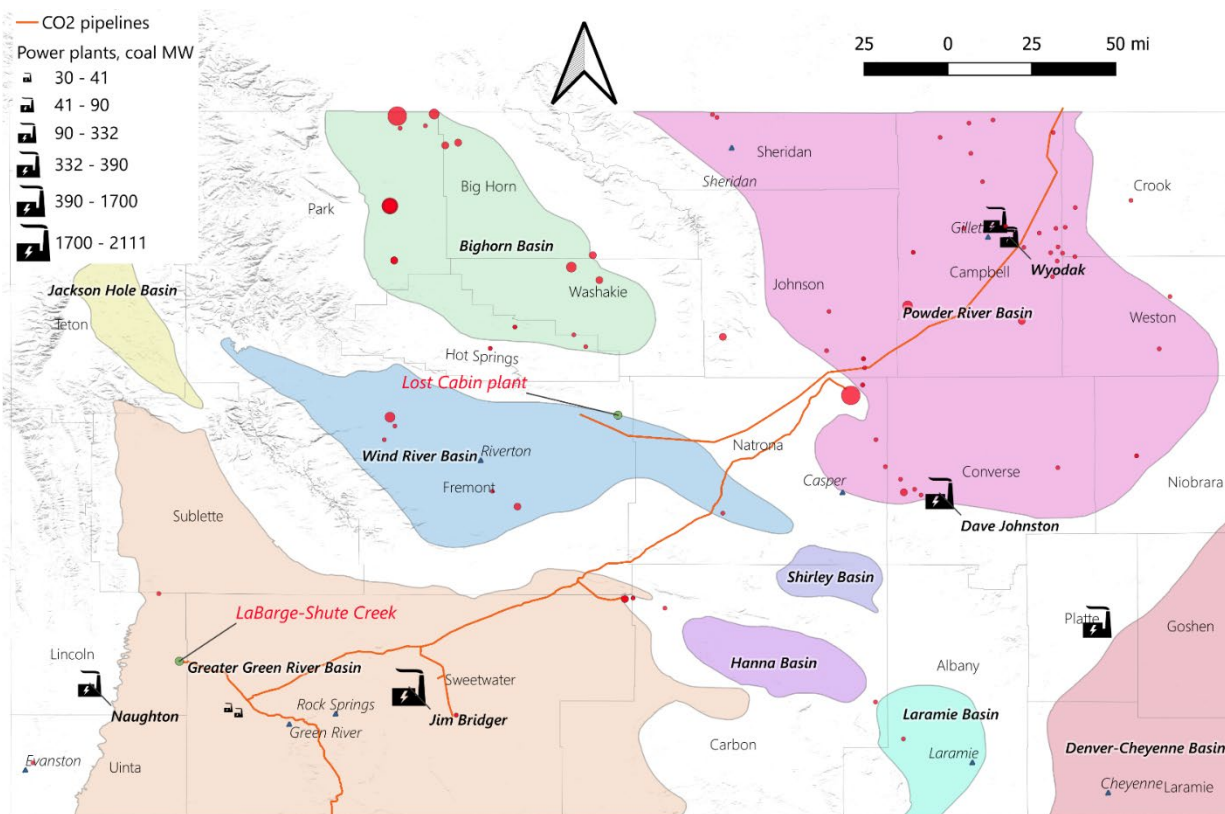


Figure 5: Wyoming Oilfields and Natural Gas Processing Facilities⁶⁶

An overview of sedimentary basins of Wyoming is provided in Table 3. The results in Table 3 indicate significant potential to store CO₂ from power plants in saline aquifers and oilfields in Wyoming. Lynds, 2013 also note that the Greater Green River Basin has geological traps required for significant CO₂ storage, including the Rock Springs uplift, Moxa arch, and the Wamsutter and Cherokee Ridge arches. These large-scale traps could be potential storage locations for CO₂ in Wyoming.

At the Rock Springs Uplift, the layers of rock have been deformed by very slow natural squeezing of the North American continent over many millions of years. The deformation now resembles nested upside-down bowls (Figure 6), or a "doubly-plunging anticline." The (nested bowls) are made of solid rock which does not allow the vertical movement of CO₂, but the space between the bowls is sandy-rock which has a lot of empty space between the sand grains. As a result, CO₂ can be pumped into the sandy-empty-space between the solid bowls and be contained. The injected CO₂ is buoyant and will rise towards the center of the upside-down bowl-shape and never escape from under it. For this study, UWy selected reservoir-rock formations which contain non-potable salt water. The entire structure is deep enough that CO₂ is efficiently stored in a dense state. The formations from deepest to shallowest, meeting the requirements for saline storage are the Madison, Weber, Nugget, and Entrada (also called the Sundance) formations.

⁶⁶ Data from EIA, WSGS, DHS, ARI, WOGCC and Energy Velocity. Note: Labels in *italics* denote population centers, other unitalicized labels are county names.

Table 3: Storage Characteristics of Sedimentary Basins in Wyoming⁶⁷

Basin	Aquifer Storage, MMT	EOR Storage, MMT	Geologic Formations	Confining Zones
Greater Green River Basin	1,928	Six Most Productive: 49 to 295 Overall: 52 to 72	Nugget Sandstone Tensleep/Weber Sandstone Madison Limestone	Gypsum Spring Dinwood Jefferson
Wind River Basin	2,913	Five Largest Fields: 7.3 to 44 Overall: 62 to 94	Tensleep Sandstone Phosphoria Formation Madison Limestone	Gypsum Spring
Bighorn Basin	6,271	Eight Largest Fields: 37 to 222 Overall: 620 to 930	Tensleep Sandstone Phosphoria Formation Madison Limestone	Gypsum Spring Dinwoody Formation
Powder River Basin	14,801	Eight Largest Fields: 10 to 61 Overall: 347 to 524	Minnelusa Formation Madison Limestone	Opeche Shale Goose Egg Formation
Hanna Basin	NA, storage not feasible			
Denver-Cheyenne Basin	NA, storage not feasible			

In contrast to the RSU, the deformation of rock layers over millions of years has created upward-bending rock layers (forming an asymmetric syncline, versus the anticlinal structure of the RSU). This right-side-up bowl shape poses a challenge for saline storage because CO₂ injected in the subsurface would tend to float away from the center of the PRB (due to buoyancy). However, studies have shown that the eastern side of the PRB is very flat (instead of a bowl) and is therefore suited for saline aquifer storage of CO₂. These studies indicate that rock formations impermeable to the vertical movement of CO₂ are present in the eastern side of the PRB. The formations from deepest to shallowest, which meet the requirements for saline storage, are the Minnelusa, Hulett, and Lakota. The Minnelusa is composed of many sub-layers of sand and limestone which are named A through E in the area around Gillette, WY and 1 through 6 in the area northeast of Douglas, WY.

⁶⁷ Source: Lynds, 201365

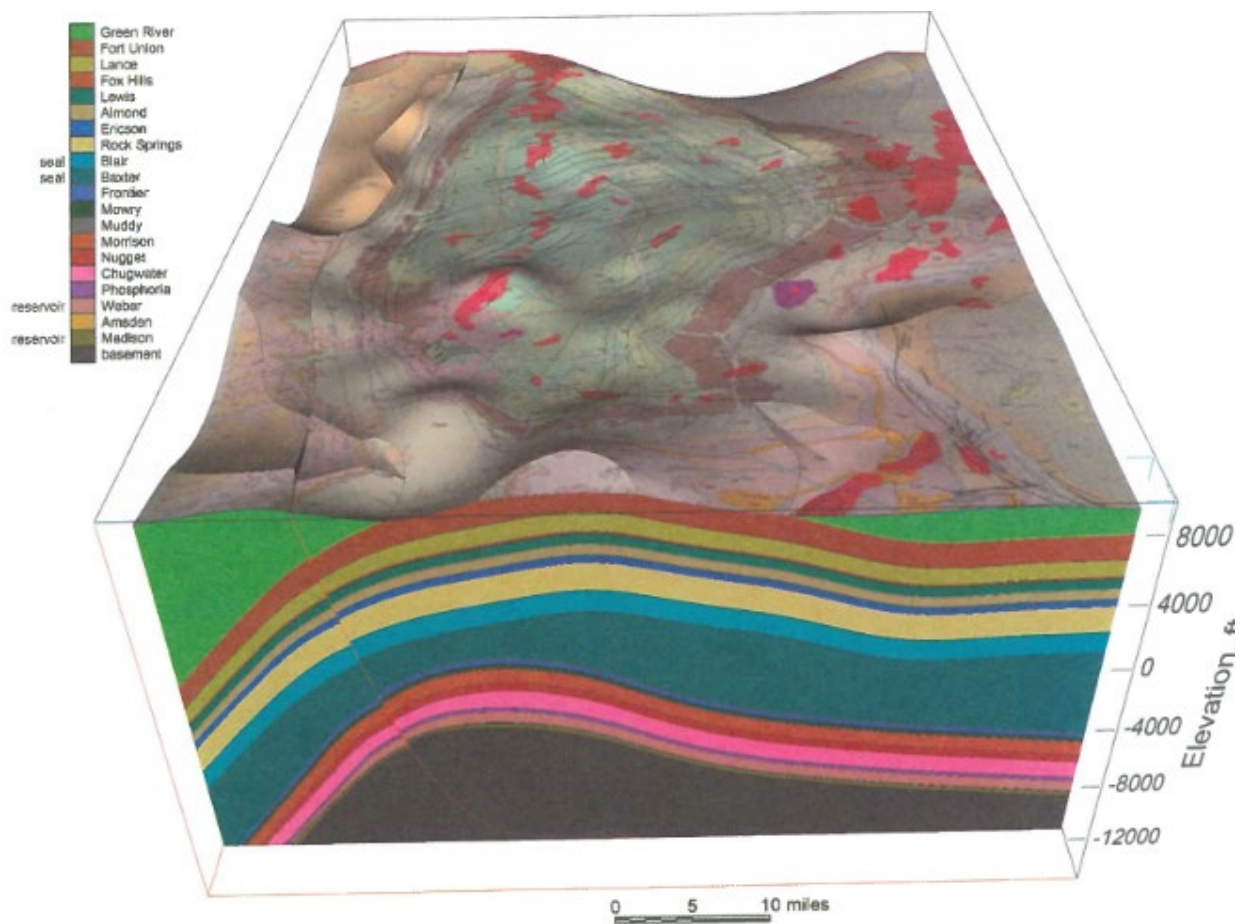


Figure 6: Structural Geologic Model of the Rock Springs Uplift.⁶⁸

This section provided an overview of regional CO₂ markets, pipeline infrastructure, and opportunities for CO₂ storage in Wyoming. The subsequent section is focused on evaluating the techno-economic feasibility of retrofitting power plant units with CCUS and storing the captured CO₂ in saline aquifers and oil reservoirs.

The two scenarios considered in the study reflect maximum CCUS deployment from PacifiCorp coal power plants in Wyoming. The study's results indicate that one plant (Dave Johnston) would not be require additional increase in the cost of electricity. On the other hand, alternative scenarios (considered, but not modeled in the study), which store lower quantities of CO₂, may be more profitable than the two scenarios (A & B). Therefore, the results of this study do not preclude the possibility that other scenarios, with lower deployment of CCUS retrofits to PacifiCorp's Wyoming power plants, could result in lower or no increase in the cost of electricity due to CCUS retrofits.

⁶⁸ Surdam, R.C., Jiao, Z., 2007 The Rock Springs Uplift: An outstanding geological CO₂ sequestration site in southwest Wyoming, <https://www.wsgs.wyo.gov/products/wsgs-2007-c-02.pdf#page=14>

Furthermore, the dispatch modeling results indicate that the overall incremental system cost in the baseline (preferred IRP) is higher than the incremental cost of electricity scenario with CCUS retrofits, which leads us to conclude that CCUS retrofits to PacifiCorp's Wyoming coal-fired power plants can lead to significant environmental and economic benefits.

4 Techno-Economic Analysis

4.1 Scenarios Modeled

The scope of the study is to retrofit nine units at four power plants with CCUS technology. The facilities and units evaluated are: Jim Bridger units 1-4, Dave Johnston units 3 and 4, Naughton units 1 and 2, and Wyodak. All the facilities are located in Wyoming and owned by PacifiCorp.

Two scenarios were evaluated as potential options for use/storage of the captured CO₂. In both scenarios, all the flue gas from the units was treated to capture 90% of the CO₂ produced.

- Scenario A: In this scenario, the CO₂ captured from each power plant is sold for use in EOR (at \$60/bbl. crude oil price) to the maximum extent practical and the remainder of the CO₂ is stored in subsurface saline aquifers in Wyoming.
- Scenario B: In this scenario, the CO₂ captured from each power plant is stored only in subsurface saline aquifers in Wyoming.

These two scenarios were compared to the Baseline IRP⁶⁹ which included accelerated retirement of units at three of the four coal plants (from 2020 to 2038) considered in the study.

A techno-economic analysis (TEA), based on the DOE/NETL carbon capture retrofit database (CCRD), provided capital expenditures (capex) and operating and maintenance (O&M) costs for CCUS retrofits at selected power plant units. Additionally, geologic and oilfield data, were used to calculate the following costs using the SimCCS modeling software for the two scenarios:

- Capex and O&M expenditures for EOR and saline storage,
- Capex and O&M expenditures for the pipeline transportation network.

SimCCS modeling results also provided marginal prices for CO₂ at each of the power plants, which were used as sources of revenue in the discounted cash-flow analysis. Finally, all capital and O&M costs (power plant CCUS retrofit costs, oilfield and saline storage costs, pipeline costs) were provided as inputs for the economic impacts analysis discussed in Section 5. Because saline storage sites set the marginal price of CO₂, the marginal costs of CO₂ were similar in both scenarios.

The basis for the economic impacts analysis is the costing of CCUS retrofits at each of the eleven units. An overview of the plants considered for analysis is presented in the following section.

4.2 Overview of Power Plants Considered for Analysis

The age, recent capacity factor, average net-plant heat rate, and environmental controls for the units considered in the study are shown in Table 4. Dave Johnston units 1 and 2 are older than other units and do not have SO₂ controls. The units at Jim Bridger have the lowest heat rates among all the units. All units, other than Wyodak are planned to be retired before 2038. Units 1 and 2 at Naughton have the highest capacity factors among all the units considered in the study (data from 2018). The methodology used for calculating the CCUS retrofit costs is described in the subsequent section.

⁶⁹ Baseline IRP refers to PacifiCorp's 2019 IRP preferred portfolio

Table 4: Design Data for PacifiCorp Units

Unit (Proposed Retirement Year)	Summer Net Capacity, MW	Age, Years	2018 CF, %	2018 Average Heat Rate, Btu/kWh	NOx Controls ⁷⁰	SO ₂ Controls ⁷¹
Dave Johnston Unit 3 (2027)	220	55	81%	11,802	OFA, LNB	SDA FGD
Dave Johnston Unit 4 (2027)	330	47	76%	11,853	OFA, LNB	SDA FGD
Jim Bridger Unit 1 (2023)	531	45	55%	10,348	OFA, LNB	Wet Sodium FGD
Jim Bridger Unit 2 (2028)	527	44	60%	10,545	OFA, LNB	Wet Sodium FGD
Jim Bridger Unit 3 (2037)	523	43	67%	10,656	OFA, LNB, SCR	Wet Sodium FGD
Jim Bridger Unit 4 (2037)	530	40	64%	10,404	OFA, LNB, SCR	Wet Sodium FGD
Naughton Unit 1 (2025)	156	57	91%	11,522	OFA, LNB	Wet Sodium FGD
Naughton Unit 2 (2025)	201	51	91%	11,036	OFA, LNB	Wet Sodium FGD
Wyodak (2039)	332	41	81%	12,703	OFA, LNB	SDA FGD

⁷⁰ OFA = Overfire Air; LNB = Low-NO_x Burners; SCR = Selective Catalytic Reduction.

⁷¹ SDA = Spray Dryer Absorber; FGD = Flue Gas Desulfurization.

4.3 CCUS Retrofit Cost Calculation

4.3.1 Assumptions and Methodology

CCUS retrofit cost calculations were based on pulverized coal plant CCRD⁷². Specifically, cost parameters were based largely on case 0 in DOE/NETL-2016/1796⁷³. In the NETL-2016/1796 report, a Cansolv™ CO₂ capture system was retrofitted to an existing PC plant fueled with Illinois No. 6 coal. The CCRD spreadsheet uses scaling exponents (based primarily on the quantity of CO₂) to calculate CO₂ capture capex and O&M costs for capturing 90% of the CO₂ from each unit at the four power plants (Dave Johnston, Jim Bridger, Naughton, Wyodak). The minimum post-retrofit capacity factor for all units was assumed to be 85%⁷⁴. Further discussion is provided in Appendix 7.1. The unit's existing cooling system was assumed to be unchanged for the CCUS retrofit.

It is important to note that this methodology has been supported with commercial data to verify accuracy of the CCRD using the Cansolv capture system. The assumptions and methods in no way preclude a different capture technology from being integrated if chosen by owners of the power plants.

The maximum CO₂ capture rate per train was assumed to be 15,772 tons CO₂ per day. To realize economies of scale, the flue gas streams from several units were 'combined'⁷⁵ for Dave Johnston Units 3 & 4 and Naughton Units 1 & 2.

For each unit at the four power plants, heat rates and pre-retrofit capacity factors were estimated from EPA CEMS data and the EIA-923 (2018) reports. Fuel costs were estimated from FERC Form-1. It was assumed that units other than Jim Bridger 3 and 4 required additional selective catalytic reduction (SCR). In costing the CCUS retrofits, we also assumed that existing flue gas desulfurization (FGD) units at units other than Dave Johnston 1 and 2 could be operated at a higher rate to achieve 1 lb. SO₂/MWh-gross specification for gas entering the CO₂ capture system.

The capital charge factor for the CCUS retrofit cost calculation was 9.3%, calculated based on an after-tax weighted average cost of capital (ATWACC) of 6.92% (from PacifiCorp's IRP). The cost-year basis for the CCUS capex and O&M costs was 2011\$. The retrofit cost factor, indicating the difficulty of retrofit versus a greenfield plant, was assumed to be 1.10. CCUS retrofit construction was assumed to begin in 2023, and CCUS unit operations were assumed to begin by Jan 1, 2026.

⁷² Mission Execution and Strategic Analysis (MESA), CO₂ capture technology – Cost of retrofit for power generation and industrial sources, August 2018.

⁷³ Mission Execution and Strategic Analysis (MESA), Eliminating the derate of carbon capture retrofits, DOE/NETL-2016/1796, May 31, 2016.

⁷⁴ If the pre-retrofit capacity factor was above 85%, it was unchanged

⁷⁵ The flue gas streams were combined if the total quantity of CO₂ captured at 100% capacity was lower than the 15,722 T/d limit. Only the Dave Johnston and Naughton units were suited for this. Each unit at the Jim Bridger power plant was above the maximum CO₂ capture rate/train limit to combine flue gas streams from individual units. Combining the flue gas from several units in close proximity to a single larger CO₂ capture system could result in some savings due to economies of scale, but the costs of the duct work, header, control systems, etc. are unknown. The study assumed that the retrofit difficulty factor of 1.1 for single units would remain unchanged for the cases where flue gas from several units was combined.

Scaled total plant costs were estimated for the following sections of the CCUS retrofit:

- Selective catalytic reduction (SCR) unit to remove nitrogen oxides (NO_x) from flue gas,
- CO₂ removal system,
- CO₂ compression system,
- Letdown turbine,
- Cooling water system,
- Balance of plant.

The total plant cost (TPC) of the retrofit was calculated as the sum of the costs of individual sections as noted above. Subsequently, the total overnight cost (TOC) was estimated as a multiple of the TPC (1.21 x TPC). The TOCs estimated from the CCRD spreadsheet were adjusted to reflect the achievement of DOE-FE R&D transformational goals on an advance schedule. This would mean that by the year 2026 the capex reduction over the CCRD baseline would translate to a 30% reduction with a 5% reduction in the O&M costs. The goal reductions are applied relative to the first year of operation and not the start of the construction period. That is, the technology which enables the capex and O&M reductions must be available for integration by the beginning of CCUS retrofit construction in 2023. The breakeven CO₂ sales price was calculated from the TOC, the capital recovery factor, CO₂ capture O&M costs, and the cost of fuel used for supplying the parasitic load.

4.3.2 Results - CCUS retrofit costs

The capex and O&M costs for retrofitting 90% CO₂ capture to individual units at the four power plants and units combined (to realize economies of scale while staying below the maximum CO₂ capture rate per train) are shown in Table 5 and Figure 7.

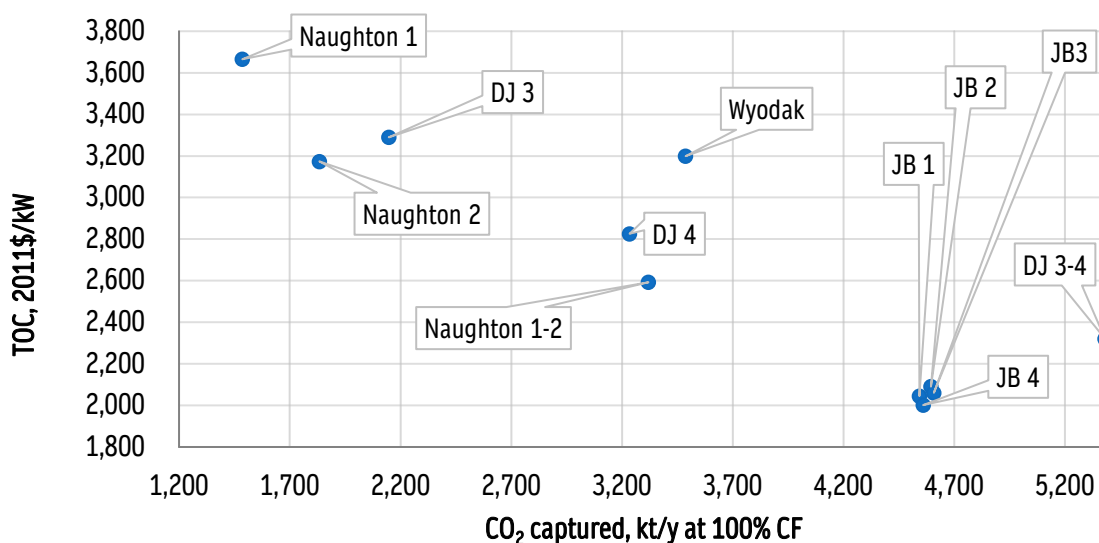


Figure 7: CCUS Retrofit Capital Costs⁷⁶

⁷⁶ JB: Jim Bridger, DJ: Dave Johnston

Table 5: Summary of TPC, TOC, and Breakeven Costs for CCUS Retrofits (2011 Dollars)

Unit(s)	Capacity Factor		Pre-Retrofit Total Capacity, MW	Post-Retrofit Heat Rate, Btu/kWh	Total CO ₂ Captured		Retrofit TOC, MM\$	Total Parasitic Load, MW	Breakeven CO ₂ Sales Price, \$/tonne	
	Pre-Retrofit	Post-Retrofit			At 100% CF, kt/y ⁷⁷	@ CF, MMT/y			Base	w/ Fuel Penalty
Jim Bridger 1	62%	85%	531	14,320	4,543	3.5	784	147	35	43.03
Jim Bridger 2	62%	85%	527	14,700	4,595	3.5	790	149	35	42.87
Jim Bridger 3	68%	85%	523	14,915	4,608	3.6	770	149	33	41.56
Jim Bridger 4	66%	85%	530	14,427	4,560	3.5	765	148	33	41.79
Wyodak	83%	85%	332	19,446	3,487	2.7	694	115	38	42.78
Dave Johnston 3-4	79%	85%	550	17,329	5,381	4.1	495	174	31	34.47
Naughton 1-2	90%	90%	357	16,103	3,319	2.7	395	108	36	42.41

⁷⁷ 1 kt = 1000 short tons, or 907.185 metric tonnes

4.4 SimCCS Data Analysis

4.4.1 Assumptions and Methodology

The SimCCS modeling framework assumed that the regulated utility would operate the carbon capture equipment and that the costs of transportation and capture would be offset by a plant-gate price of CO₂. It was assumed that the suppliers of CO₂ would receive the any tax credits available for CO₂-EOR or saline aquifer storage of CO₂. The utility would also receive the market-clearing price for any CO₂ sold: that is, all oil producers within a pipeline network would pay the same competitively determined market price. The implication of this framework is that if the combination of costs, tax credits, and sales revenues generated a net cost, that cost would be passed to the power plant as part of the retrofit cost analysis. If the combinations of costs, credits, and revenues generated a net profit, that profit would be available to reduce the cost of generating the electricity.

In all cases, carbon capture source information was based upon parameters set by, and carbon capture cost analyses discussed in the previous section. At 90% capture efficiency the four power stations in this study produce 23.67 MMT/y of CO₂ for EOR/storage.

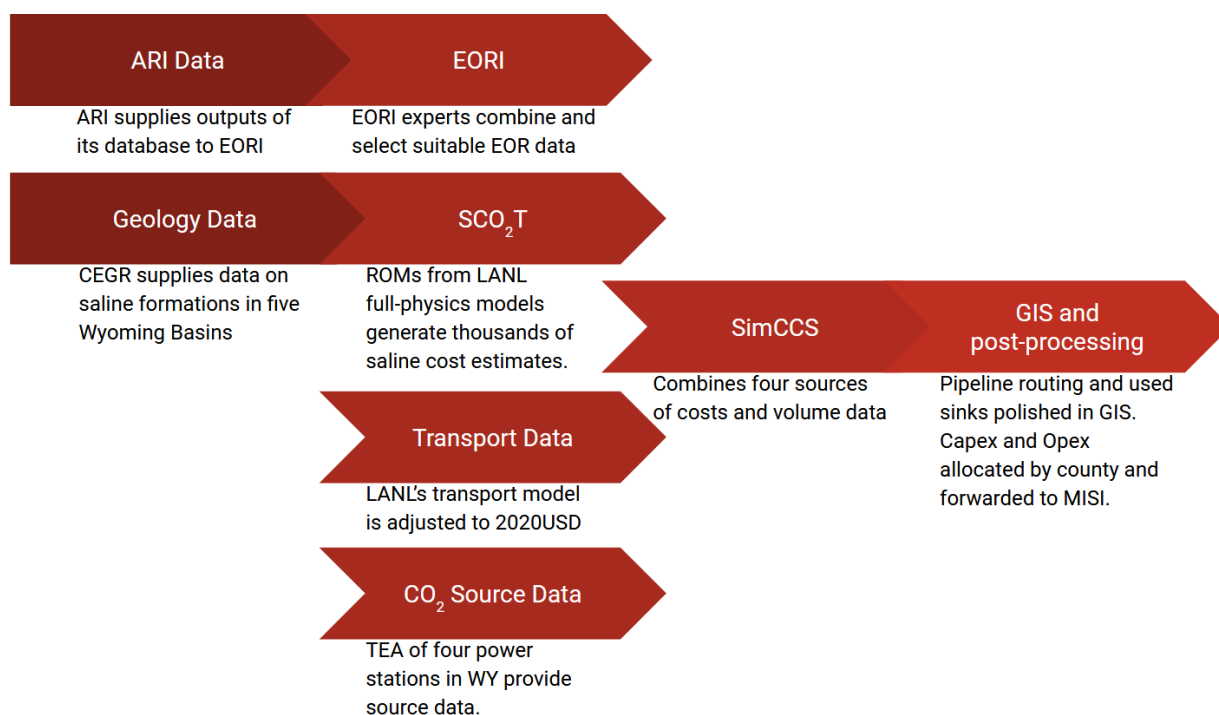


Figure 8: Scenario A SimCCS Workflow

CO₂-EOR raw data, geologic aquifer data, transport infrastructure data, and CCUS retrofit cost data were processed to produce unit-cost and capacity-volume data which are inputs to SimCCS. SimCCS was run to analyze different capture amounts, oil-market conditions, storage options and pricing assumptions. Two scenarios selected for evaluation were post-processed to supply data for the DCF and economic impacts analysis. The workflow is shown in Figure 8.

To perform a state-wide analysis of CO₂ demand, it is important to understand the quantity of CO₂ stored in oilfields or saline aquifers, and the price (or cost) of storing the CO₂. For oilfields, this is expressed as a price these oilfields can afford to pay for the CO₂ while meeting a required hurdle rate. Two tools were used to provide the price-quantity data to SimCCS simulations in the study: Advanced Resources International's CO₂ Prophet EOR modeling runs, and LANL's SCO₂T modeling tool for generating storage volume-cost estimates for saline storage locations.

4.4.2 45Q Tax Credit Application

Compared to other states such as Texas or Illinois, Wyoming has both low-cost coal resources to fuel coal plants and a wealth of potential CO₂-EOR fields that can pay a meaningful price for the CO₂ captured⁷⁸. The federal Section 45Q carbon capture/storage tax credit increases linearly year-by-year at a statutorily prescribed schedule that by 2026 reaches a value of 50\$/T for saline storage and 35\$/T for CO₂-EOR, thereafter rising annually with inflation⁷⁹. Section 45Q tax credits may only be claimed in the first twelve years of a project, whereas the techno-economic analysis of power plants used a thirty-year horizon, as did other capital investment calculations used in the study. To harmonize timeframes for the analysis, the 45Q credit actually received over twelve years was levelized to a thirty-year tax credit, using discount rates consistent with those used in the CCUS retrofit cost estimation. The resulting tax credits assumed for each year were \$26.11/T for EOR and \$38.95/T for saline aquifer storage. These were added to the break-even cost of EOR and the net-unit cost of saline storage from SCO₂T before running SimCCS. All unit costs were adjusted to 2020USD for consistency. The solution should not be affected by the levelization of the tax credit because of SimCCS employs a perfect foresight approach (i.e., all years at the same time).

4.4.3 EOR Field Inputs and Methodology

The key drivers of CO₂ demand for EOR are the price of oil and the productivity of the injected CO₂ in each oilfield. If oil prices are high, all fields can pay a higher price for CO₂ than if oil prices were low. In the extreme case of oil prices below \$40/bbl. most fields are unwilling to enter the CO₂ market. However, oil fields are heterogeneous; and a field that has ideal geology and produces a large amount of oil per ton of CO₂ injected can always afford to pay more than a field with less ideal geology that produces smaller amounts of oil per ton of CO₂ injected. Details of the database and the CO₂ Prophet modeling runs are provided in Appendix 7.2.

⁷⁸ As an example. assuming moderately high oil prices (i.e., in the \$50/bbl. range), the authors estimate that oilfields that could pay approximately \$30/T to the entity capturing the CO₂ (CO₂ capturer) while still earning adequate financial rates of returns at the oilfields (approximately 10 MMT/y CO₂ can be stored at this price level). Adding in the \$35/T federal Section 45Q tax incentive for captured CO₂ used in oilfields, the potential "revenue" is approximately \$65/T. On the other hand, the CO₂ capturer receives a \$50/T federal Section 45Q tax credit for storing the CO₂ in saline aquifers. The costs of permitting, equipping, and injecting at the storage site are estimated to be approximately \$5/T. The net 'revenue' from storing CO₂ in saline aquifers, which is the tax credit less the cost of storing CO₂, is approximately \$45/T. Therefore, assuming that both EOR sites and saline storage sites are within reasonable striking distance from a capture plant, the net revenues⁷⁸ available are almost \$20/T higher if the CO₂ is directed to the EOR site.

⁷⁹ Because SimCCS focuses on the net cost across the CCUS system, the system is unconcerned with who claims the 45Q tax credit. For ease in representing the different tax credits for CO₂-EOR and saline storage, the tax credit was computed as though it were claimed by the sink. In practice the credit would most likely be claimed by the source. This representation is mathematically equivalent and allows for simple representation of the legal difference between sinks.

To understand the relationships between CO₂ demand and oilfield productivity, three analyses of demand across all the Wyoming fields at hypothetical, steady, non-escalating oil prices of \$40/bbl., \$50/bbl., and \$60/bbl. were performed. The analysis with \$60/bbl. oil price was chosen for Scenario A (where the maximum quantity of CO₂ is delivered for EOR, the rest being stored in saline aquifers). Scenario A, with \$60/bbl. crude oil price and Scenario B (with saline aquifer storage, and no CO₂-EOR), were assumed to bound the possibilities for potential CCUS deployment in Wyoming. For each of the three price scenarios, the worst fields, i.e., the fields that could not make money if they received CO₂ for free, at a price of \$0/T were eliminated. The following key outputs were provided for the remaining fields:

- The highest price the field could pay for CO₂ (per T) while still meeting profitability goals⁸⁰.
- The number of years the field would carry out the flood, and the quantity of CO₂ purchased per year. (Average annual purchases, as opposed to specific annual new CO₂ purchases for each year, were used in this analysis.)
- The amount of oil that would be produced per T of CO₂ injected, annual average and total oil produced.
- Total capital expenditures over the life of the flood and average annual operating expenses.

The analyses indicated that if Wyoming coal power plants were retrofit with CO₂ capture equipment, a significant volume could be absorbed by oilfields that would pay to obtain the CO₂. Secondly, is that the quantity of CO₂ purchased by the oilfields is significantly larger at higher oil prices. Third, at low oil prices it is unlikely that oilfields can absorb all of the 23.7 million MT/year of CO₂ that would be captured if all of the studied power plants in this study were retrofit with CO₂ capture⁸¹.

4.4.4 Saline Site Inputs and Methodology

Storage volume-storage costs estimates were developed for several potential geologic saline aquifer storage sites using the SCO₂T tool from LANL, analogous to the CO₂-EOR modeling approach which used CO₂ Prophet modeling runs with an internal hurdle rate to generate such data. SCO₂T is a tool that generates the per-site CO₂ storage volume and storage costs using geologic input parameters such as porosity, permeability, depth, and unit thickness. Geologic data across five Wyoming basins from Wyoming State Geological Survey (WSGS) and University

⁸⁰ For example, if Field #42 could afford to pay \$25/T for CO₂ at a \$60/bbl. oil price; and prices for CO₂ were \$30/T, Field #42 would be priced out of the market. Conversely, if the field could afford to pay a maximum \$25/T, it would be beneficial for the operators of Field #42 if the market ultimately settled at \$15/T as carbon capturers sought to find customers for their CO₂.

⁸¹ To summarize the study's findings on CO₂-EOR, we focus on the amount of volume that oilfields could take while paying a price of at least \$20/T. The significance of that figure is that the capture cost estimated is in the range of \$35-45/T, and transportation cost is estimated generally to be less than \$5/T, or a rough midpoint total capture and transport cost of \$45/T. If an oilfield can pay at least \$20/T and the capturer can also garner a \$35/T tax credit, we can reach a total "revenue" of \$55/T, which would be more than offset the cost of capturing CO₂.

- At a \$40/bbl. oil price, a total of 11 million MT/yr. could be taken at a price of \$20/T or better.
- At a \$50/bbl. oil price, a total of 19 million MT/yr. could be taken at a price of \$20/T or better.
- At a \$60/bbl. oil price, a total of 22 million MT/yr. could be taken at a price of \$20/T or better.

of Wyoming's School of Energy Resources (SER) was used in this analysis^{82,83,84}. These data were processed through SCO₂T to produce estimates of storage volume and cost-per-tonne to store at over 80 locations and formations.

The SCO₂T tool's configuration was modified for full seismic collection every 5 years during operation and every 25 years after site closure. All other monitoring, verification, and accounting (MVA) options were left as default. The key outputs recorded in reduced 10th, 50th and 90th percentile (P10-P50-P90) form included storage volume, cost-per-tonne, capex, and opex.

In the subsequent step, SimCCS was run with the required variables of storage volume and cost-per-tonne. The other two variables, the storage site's capex and opex were used as input parameters for the economic analysis.

4.4.5 SimCCS Modeling Runs

SimCCS is a CCUS cost-optimization program that aids scientists, energy planners, businesses, and policy makers faced with the challenge of estimating the costs and feasibility of capturing from multiple CO₂ sources, transporting CO₂ over a to-be-built network of pipelines to reach numerous potential CO₂-EOR sites or saline storage sites. It can use geospatial information to optimize nearly limitless possible pipeline configurations connecting various combinations of sources and sinks. For each of these possible scenarios, SimCCS can estimate profits or losses by component and as a total. CCUS retrofit costs from the CCRD, EOR volumes and revenues from CO₂ Prophet, and saline storage volumes and costs estimated via SCO₂T were used as inputs in this study. SimCCS's built-in network transportation costs were adjusted to 2020USD, and cost-surface multipliers for the specific topography of the pipeline routes were used. Details of the technical aspects of SimCCS are described in Appendix 7.3. The analysis was completed according to the following steps:

1. Select scenarios for SimCCS: Scenarios which focused on minimizing costs given certain volumes of CO₂ to be captured were modeled. Other scenarios, which were modeled, but not included in this report, considered capturing as much volume as possible subject to avoiding any costs to electric ratepayers. The scenarios selected are:
 - a. Scenario A: This scenario considers a combination of CO₂-EOR and saline aquifer storage in the state of Wyoming. Oilfields for CO₂-EOR were chosen based on meeting an internal hurdle rate (15% return on equity) at a crude oil price of \$60/bbl.
 - b. Scenario B: This scenario considers only geologic storage of CO₂ in saline aquifers in the state of Wyoming
2. Run SimCCS Scenarios: The model was run to minimize total system costs assuming 90% CO₂ capture deployment on Dave Johnston 3&4, Naughton 1&2, Wyodak, and Jim Bridger units 1-4. The total network CO₂ volume to be captured and investigated was 23.67 MMT/y. The results were postprocessed to provide input on the saline storage and EOR sites for further evaluation.

⁸² Lynds, Ranie M. "Geologic Storage Assessment of Carbon Dioxide (CO₂) in the Laramide Basins of Wyoming Technical Memorandum No. 3" 2013.

⁸³ Surdam R.C. (ed) (2013) Geological CO₂ Storage Characterization: The Key to Deploying Clean Fossil Energy Technology, Springer, New York, NY.

⁸⁴ Ganshin Yuri, Geophysical Description chapter in CMI's final report "Integrated Pre-Feasibility Study of a Commercial-Scale CCS Project in Formations of the Rock Springs Uplift, Wyoming" submitted 2019.

The inputs of capture costs at the power plant sources, transport costs along a particular pipeline route over Wyoming geography, sink costs for CO₂-EOR and sink costs for saline were fed into SimCCS and the solution to each of the three parts (source, transport, and storage) linked to the others. The interconnected and complex problem was then exported to CPLEX and solved. SimCCS outputs a Java visualization of the sources, sinks, and pipelines which connect them in the optimal solution. Additional outputs included a collection of shapefiles with the same information in GIS-compatible format, a results spreadsheet listing which sinks/source/pipelines were used at what capacities or utilizations, and a table of total costs by year, total costs by unit of CO₂, and broken down by source, transport, and storage components. These shapefiles and spreadsheet data were post-processed in GIS applications.

4.5 SimCCS Results

The two scenarios Scenario A and B, are visualized in Figure 9 and Figure 10, and are summarized in Table 6. The difference between these two runs is market-based. 60\$ per barrel EOR finds that the four power stations form isolated mini-networks, and accordingly assigns a minimum cost to each equal to the saline “surplus” site which is part of the mini-network because the lowest-paying member of a network sets the market-clearing price. Scenario B is market-agnostic to both the oil market and to supply and demand forces as all saline sinks in the same formation of a basin are assumed to have similar costs.

Table 6: Total System Capture, Transport, and Injection Costs (2020 Dollars)⁸⁵

Cost Item	Scenario A	Scenario B
Total System CO ₂ Volume	23.67 MMT	23.67 MMT
Capture Cost	\$1,138MM \$48.07/T	\$1,138MM \$48.07/T
Transport Cost	\$81.22 MM \$3.43/T	\$15.21MM \$0.64/T
Injection Revenues + Section 45Q tax credit - Injection Cost	-\$807.47 MM -\$34.11/T	-\$795.92MM -33.63/T
Combined Total	\$411.66 MM -\$17.39/T	\$357.20 MM \$15.09/T

4.5.1 Scenario A

This scenario reflects how CO₂ would be priced and moved around Wyoming when crude oil costs 60\$/bbl.⁸⁶ It assumes that full carbon capture is applied to each of the principal coal units under investigation: DJ 3&4, Naughton 1&2, Wyodak, and JB 1-4, resulting in total volume captured of 23.67 MMT/y. With such a large volume of CO₂ captured, a possible unattractive outcome of such a scenario might be that there might be an insufficient

⁸⁵ Note that aggregate values for all power plants are provided in this table

⁸⁶ It is necessary to specify an oil price because the price paid for CO₂ is traditionally tied to the price of crude oil

amount of CO₂ demand from productive oilfields, with CO₂ prices needing to be negative to dispose of all CO₂. In this scenario, saline storage options in each basin were merged to simplify computing and optimization under SimCCS.

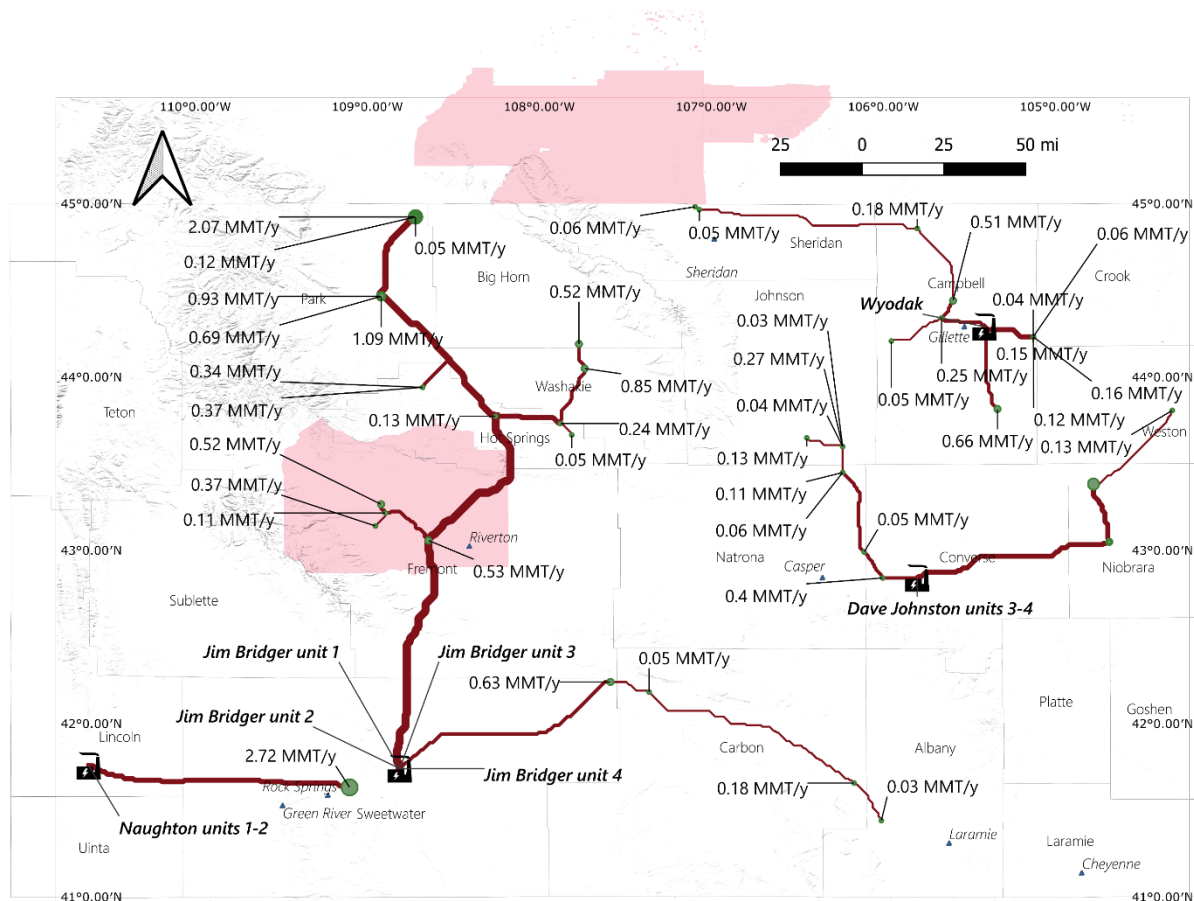


Figure 9: SimCCS Scenario A Solution⁸⁷

4.5.2 Scenario B

This scenario assumes that full carbon capture is applied to each of the principal coal units under investigation: DJ 3&4, Naughton 1&2, Wyodak, and JB 1-4, resulting in total volume captured of 23.67 MMT/y. The change in the second scenario is that no injection for CO₂-EOR is permitted. This could be because the oil market is unfavorable (i.e. below about 40\$/bbl. of crude), the involved decision makers choose to avoid EOR (perhaps due to policy or high volatility in the oil market), or the amounts of CO₂ to store greatly exceed outstanding EOR demand.

⁸⁷ Note: Line widths correspond to the quantity of CO₂ carried by pipeline (proxy for pipeline diameter). Numbers indicate the CO₂ stored in each sink. Sources, transportation network and sinks (both oil reservoirs, and saline aquifers) are shown.

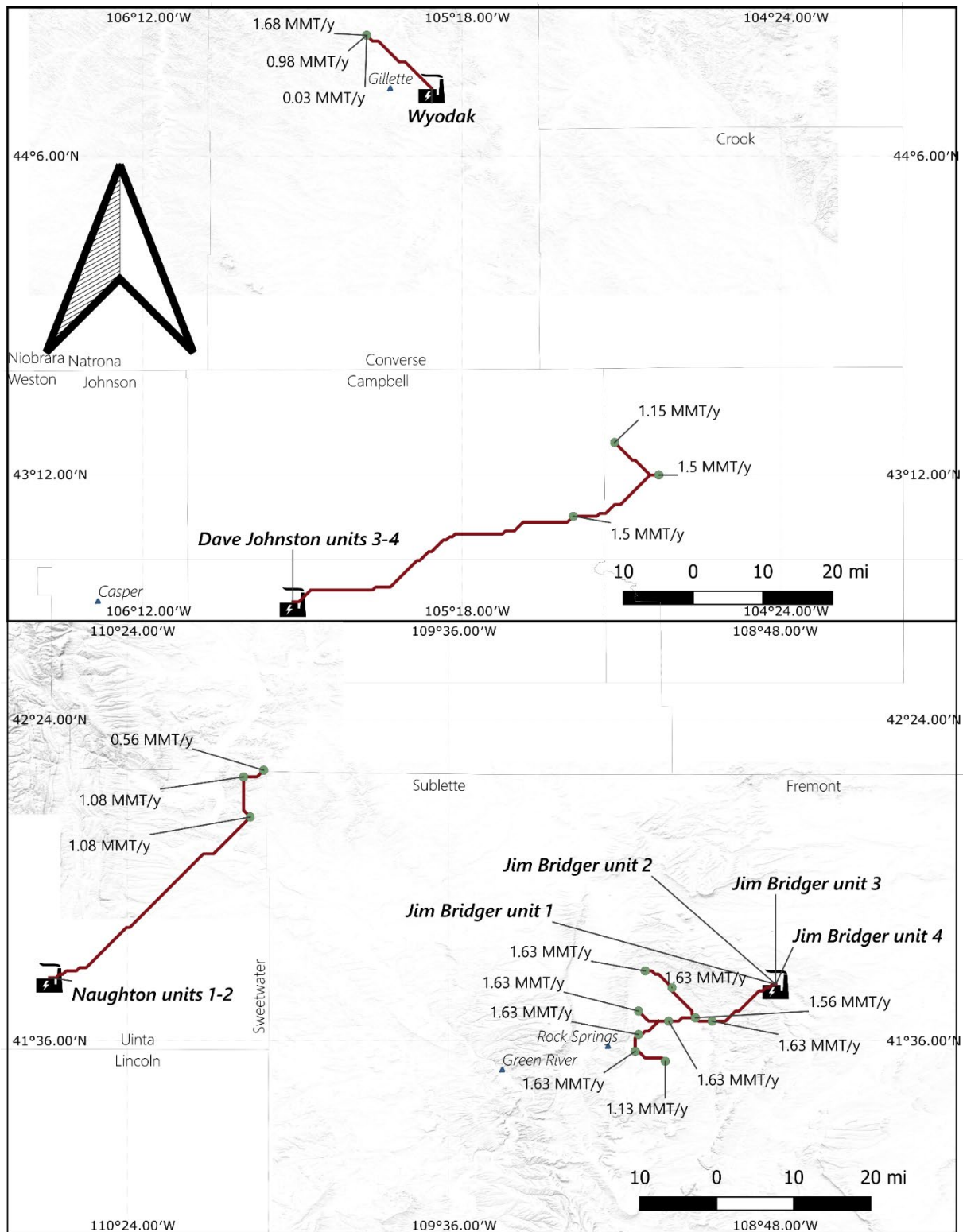


Figure 10: SimCCS Scenario B Solution⁸⁸

⁸⁸ Note: Line widths correspond to the quantity of CO₂ carried by pipeline (proxy for pipeline diameter). Numbers indicate the CO₂ stored in each sink.

4.5.3 Scenario Comparison

The two scenarios used the same input data, but as seen in the figures visualizing the two scenarios, the difference in pipeline length is significant, although the unit-cost is similar. This effect is seen in the O&M costs and capex for the two scenarios.

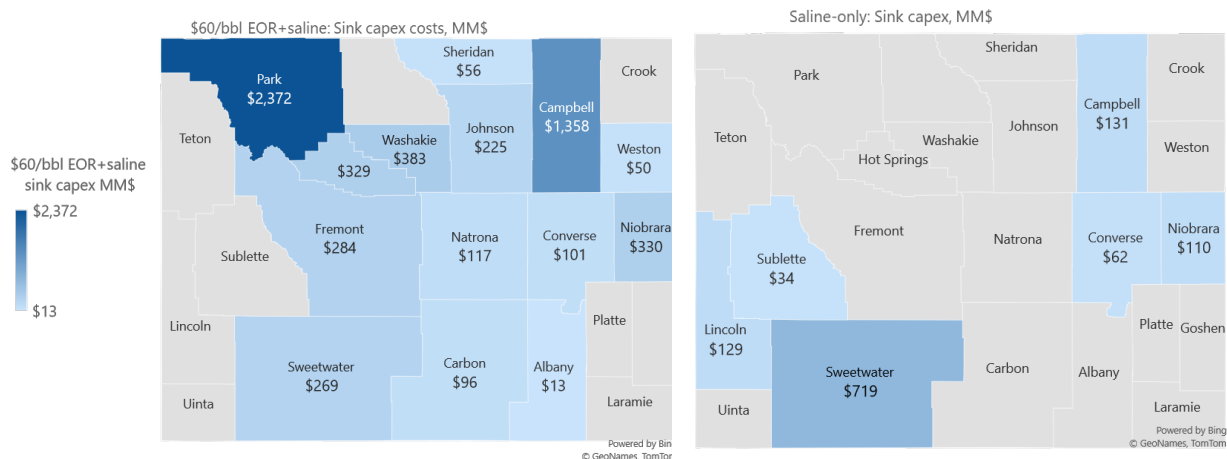


Figure 11: Capex by County – Scenarios A&B (A on the left, B on the right)

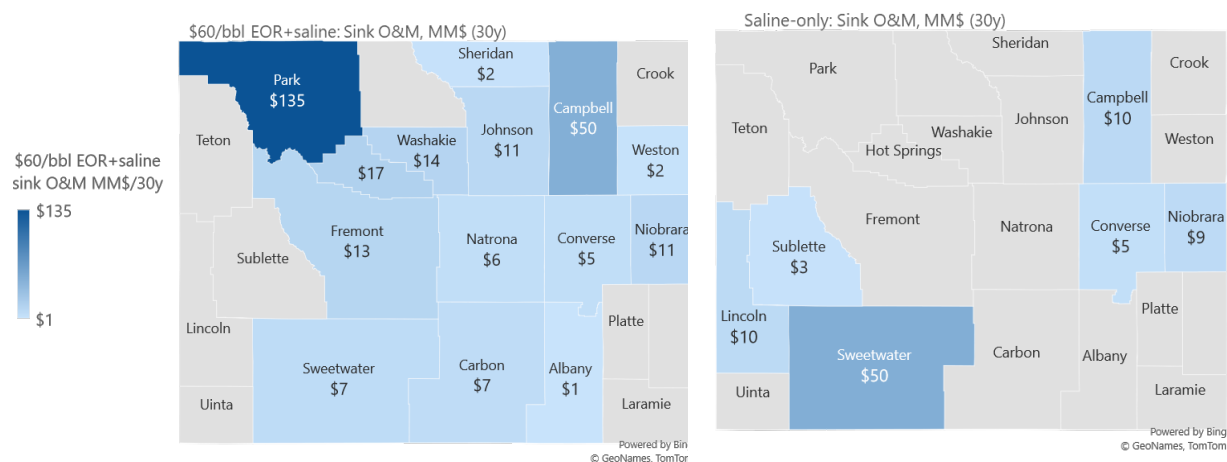


Figure 12: O&M Costs by County – Scenarios A&B (A on the left, B on the right)

Figure 13 shows that the pipeline capex and O&M costs are about five times larger in Scenario A compared to Scenario B. The ratio of capex to O&M costs changes between the cases because saline sites must pay very high monitoring, verification, and accounting (MVA) costs. The effect of the capex and O&M costs, shown in Table 6, on the unit costs shown above is not straightforward. This shows that although the plant-gate price of CO₂ is the same in both scenarios, the additional investment in Scenario A can lead to higher economic impacts.

In Table 6, there at first appears to be only slight differences between these two scenarios. The most notable is the higher transportation cost in Scenario A which is due to the EOR sites being much further from the power plants than the saline sites. However, this increase is partially offset for Jim Bridger has an attractive saline sink

along the route to the EOR sites, which saves approximately \$0.44 per tonne. This raises the market clearing price on all of Jim Bridger's network.

A less significant difference is the relocation of Naughton's CO₂ from the LaBarge platform to the Rock Springs Uplift (RSU). The RSU is further from Naughton than LaBarge but is a less expensive CO₂ sink. As a result, this change of sink provides only \$0.17 of savings. The RSU was modeled in this work with a discrete capacity, but in real-world implementation injection capacities have a degree of vagueness which might allow for Naughton to inject on the west side of the RSU at the same time as Jim Bridger injects on the east side.

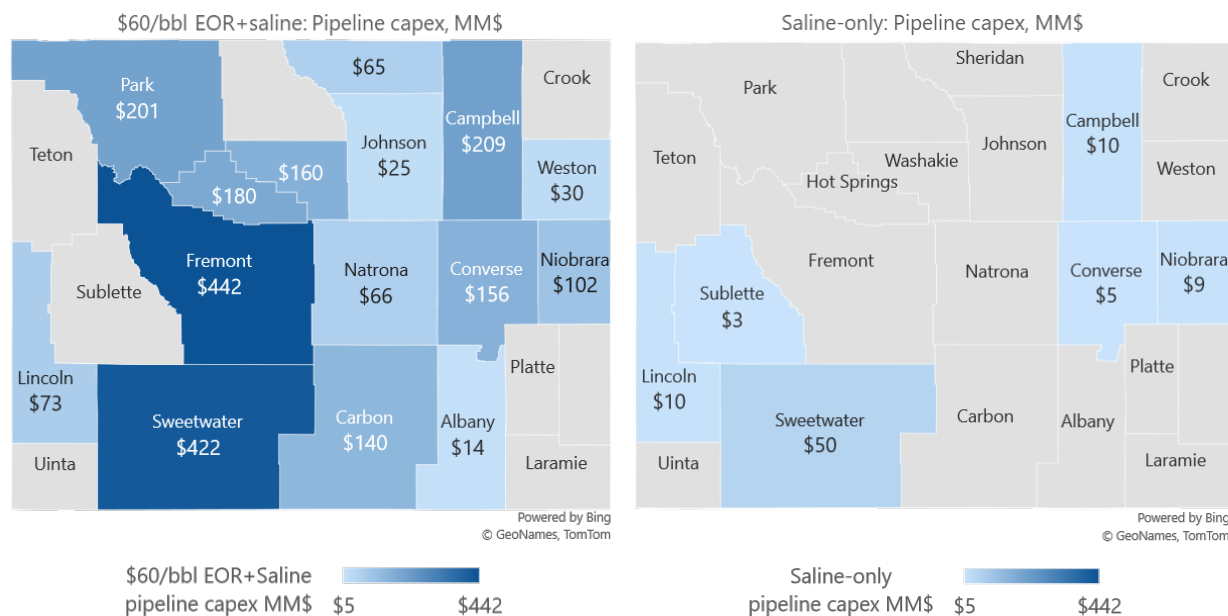


Figure 13: Pipeline Capex by County – Scenarios A&B

4.6 Summary of Cost Analyses

A summary of the CCUS retrofit capex, O&M costs, breakeven CO₂ prices, CO₂ transportation cost, and the marginal selling price of CO₂ is provided in Table 7. The results show the importance of capture costs in system economics. Capture cost is the primary control on whether a given system is profitable or not. This control can be seen in the nominally higher marginal prices of CO₂ for the Dave Johnston units.

The following analysis assumes a constant sale price for CO₂ at the plant gate for both scenarios. Scenarios A and B differ in the amount of infrastructure built to store the CO₂ from the power plants. When CO₂ is sold for EOR, it is assumed that the additional cost of CO₂ transportation is borne by the oilfield operators. Even with the additional cost, the price of CO₂ for most oilfield operators is significantly lower than what they would be willing to pay for CO₂ in a scenario without saline storage.

The CCUS retrofit cost calculations from Table 5 indicate the costs for retrofitting 90% CO₂ capture at the power plants. A discounted-cash flow (DCF) analysis was performed to calculate the economic impacts of the retrofit on the rates to Wyoming taxpayers. The inputs to the DCF are provided in

Table 7. Revenues for the DCF analysis are based on the quantity of CO₂ captured and the marginal price of CO₂ from the SimCCS calculations.

Table 7: Inputs for the Discounted Cash Flow (DCF) Analysis (2020 Dollars)

Plant / Unit	MMT CO ₂ /y	Capture Costs		Breakeven CO ₂ price, \$/T	Marginal CO ₂ price, \$/T	Transportation cost, \$/T	Plant-gate CO ₂ price, \$/T
		TOC, \$/kW	O&M, \$/T				
DJ 3&4	4.15	2720	14	40.42	33.74	1.40	32.34
JB 1	3.50	2398	16	50.46	33.5	0.35	33.15
JB 2	3.54	2451	16	50.26	33.5	0.35	33.15
JB 3	3.55	2416	15	48.72	33.5	0.35	33.15
JB 4	3.52	2347	16	49.00	33.5	0.35	33.15
Naughton 1&2	2.72	3040	16	49.73	31.54	1.26	30.28
Wyodak	2.69	3751	17	50.15	32.27	0.40	31.87

DCF calculations were performed for all the power plant units considered in the SimCCS calculations (Jim Bridger units 1-4, Dave Johnston units 3 and 4, Naughton units 1 and 2 and Wyodak). Coal price escalation for the DCF calculations was based on the increase in Wyoming PRB mine-mouth coal prices as per the 2020 EIA annual energy outlook (AEO). GDP deflators were based on annualized GDPPCTPI from 1987-2018 (FRED) and AEO 2020 projections from 2019-2050.

The results of the DCF analysis are shown in Table 8 showing the COE for each unit after retrofitting with CCUS technologies..

Table 8: Impacts of CCUS Retrofits on the Costs of Electricity

Plant / Unit(s)	Production cost with CCUS, 2026\$/MWh
Dave Johnston 3&4	23.4
Jim Bridger 1	61.2
Jim Bridger 2	59.4
Jim Bridger 3	56.1
Jim Bridger 4	56.7
Naughton 1&2	53.7
Wyodak	46.4

The COE calculation does not take into consideration potential sources of revenue which might reduce any effect to the end consumer. The COE increase could be significantly ameliorated by environmental compliance considerations such as participation in a carbon-trade market such as under the California cap and trade market. The analysis shows the tradeoffs among a slightly higher marginal price of CO₂ when targeting EOR sale versus higher transportation costs. CCUS retrofits are the most favorable at Dave Johnston Units 3&4 and slightly more favorable at Jim Bridger Units 3 and 4 and Naughton Units 1&2 compared to the other units.

4.7 Summary of TEA Findings

1. Power stations in Wyoming, like potential sinks, are spread around the state which favors “mini-networks” where one CO₂ source supplies multiple local sinks. This contrasts with an integrated state-wide network. The authors recognize that a state-wide network may still be favorable as a risk-management technique
2. CO₂ captured from all four considered plants over thirty years can be stored through CO₂-EOR with small surplus storage in saline sites
3. Capture and utilization of 23.67 MMT/y oversupplies the CO₂-EOR market and requires additional storage of CO₂ in saline aquifers. If electrical arbitrage, other state/federal support, avoided costs, or public support could add a combined 25\$ per tonne either requested scenario would then become profitable outright
4. Saline storage is immune to changes in the oil market and is a valuable sink for surplus CO₂ beyond what EOR can use. If saline became profitable outright, then saline-only systems could be deployed anywhere and everywhere in the state because they are not limited by market forces and exist in proximity to every major Wyoming power station.
5. CO₂-EOR requires longer pipelines than saline storage. This raises capex and O&M expenditures which could translate into higher job creation.

5 Jobs and Economic Impact Analysis

PacifiCorp is considering retiring a number of coal plants in Wyoming earlier than originally scheduled. These include Jim Bridger Units 1&2, Naughton Units 1&2, and the entire Dave Johnston power plant. As discussed earlier, this study looks at several scenarios where CCUS retrofits are applied to PacifiCorp's Wyoming plants. This analysis evaluated the potential job impacts counties of the CCUS scenarios (Scenario A and B) compared to the Baseline IRP scenario on Wyoming and on Campbell, Converse, Lincoln, and Sweetwater. In addition, this analysis identified the implications for the occupational jobs and skill requirements resulting from the coal plant CCUS retrofits.

5.1 Assumptions and Methodology

For the economic impact analysis of both CCUS scenarios, the following assumptions were made:

- CCUS retrofits will be installed all of the evaluated units between 2023 and 2026.
- All of the evaluated units and associated mines would continue operating through 2055.
- Naughton Unit 3 will be converted to natural gas, per the Baseline IRP.
- Dave Johnston Units 1 and 2 will be closed in 2027, per the Baseline IRP.
- All of the captured CO₂ is used for EOR or sequestered in saline storage in Wyoming (Scenario A assumes a combination of EOR and saline storage; Scenario B assumes only saline storage).

For the economic impact analysis of the Baseline IRP scenario, the following assumptions were made:

- Jim Bridger Unit 1 will close in 2023 instead of 2037.
- Jim Bridger Unit 2 will close in 2028 instead of 2037.
- Naughton Units 1&2 will close in 2025 instead of 2029.
- Naughton Unit 3 will be converted to natural gas.
- Dave Johnston will be completely decommissioned in 2027.
- Wyodak continues to operate through 2037 without CCUS.

5.2 Job Impact Analysis Results

Figure 14 shows the annual job impacts of the CCUS scenarios and the Baseline IRP scenario.

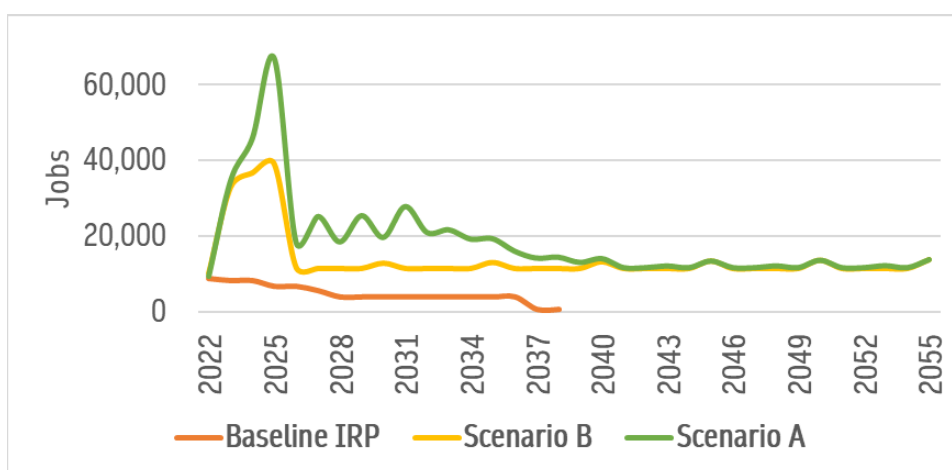


Figure 14: Job Impact Analysis by Year

The job impacts analysis showed that Scenario A resulted in:

- A maximum of 67,000 jobs are created in 2025;
- A range of 20,000 to 28,000 jobs are created annually from 2026-2031;
- 21,000 jobs are created in 2032, declining to about 14,000 jobs in 2040;
- 12,200 jobs are created annually between 2041 and 2055.

The job impacts analysis showed that Scenario B resulted in:

- A maximum of 39,000 jobs are created in 2025;
- A range of 12,000 to 13,000 jobs are created annually from 2026-2055.

In comparison, the job impacts analysis showed that the Baseline IRP scenario resulted in:

- A maximum of 8,700 jobs are created in 2022;
- A declining number of jobs are created annually, reaching 3,800 in 2028;
- 3,800 jobs are created annually from 2028-2036;
- 500 jobs are created annually from 2037-2038;
- No jobs are created after 2038.

Figure 15 shows the jobs impacts in each county in 2025 – the year of the maximum job impacts of the CCUS scenarios, due primarily to CCUS retrofit construction.

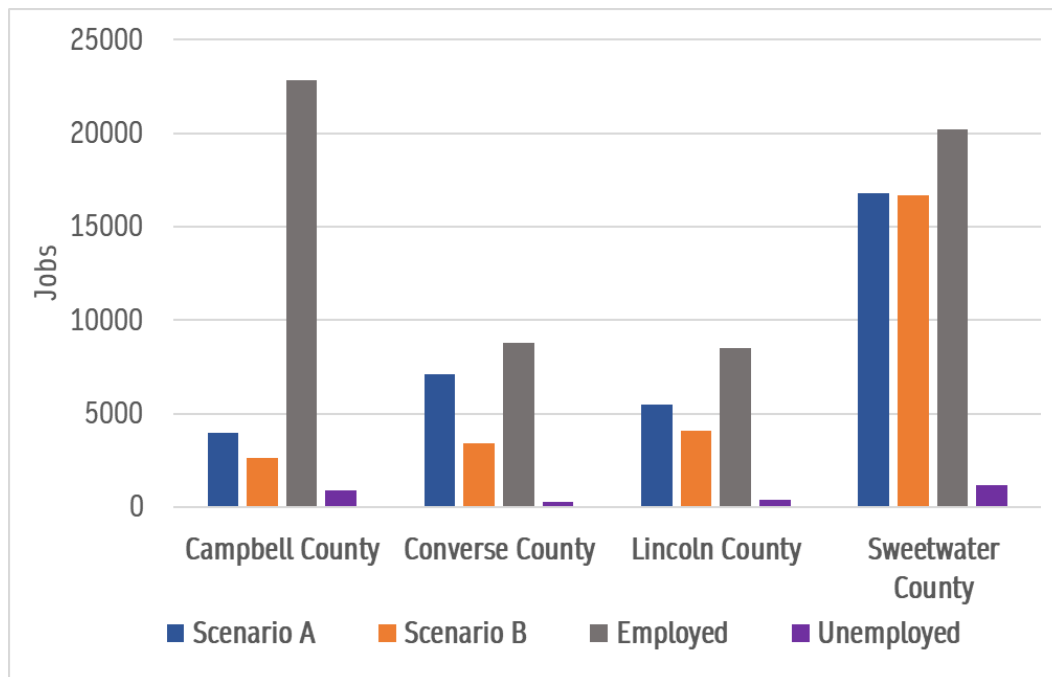


Figure 15: Relative Job Impacts in 2025 by County

Scenario A creates substantially more jobs every year from 2022 through 2055 than the Baseline IRP scenario. More specifically, Scenario A creates more than 10 times as many jobs in 2025, approximately three to four times as many jobs each year from 2026-2036, and nearly 30 times as many jobs in 2036 and 2037. Furthermore, after 2038 Scenario A creates over 12,000 jobs annually whereas the Baseline IRP scenario creates no jobs.

While not as significant, Scenario B also creates more jobs every year from 2022 through 2055 than the Baseline IRP scenario. More specifically, Scenario B creates more than six times as many jobs in 2025, approximately three to four times as many jobs each year from 2026-2036, and nearly 23 times as many jobs in 2036 and 2037. Furthermore, after 2038 Scenario A creates over 12,000-13,000 jobs annually whereas the Baseline IRP scenario creates no jobs.

Figure 16 shows that the near-term job impacts on each county will be significant. For example, in 2025, the jobs created by either CCUS scenario in Sweetwater County comprise 83% of the total January 2020 jobs in the county and more than 14 times the number of unemployed in that month. These findings indicate that for the CCUS scenarios, each county would likely be faced with problems of workforce adequacy and extreme strains on local housing and other infrastructure.

Figure 16 shows the long-term average numbers of jobs created annually from 2026-2055 in each county for Scenarios A and B compared to the actual number of jobs and unemployed in each county in January 2020.

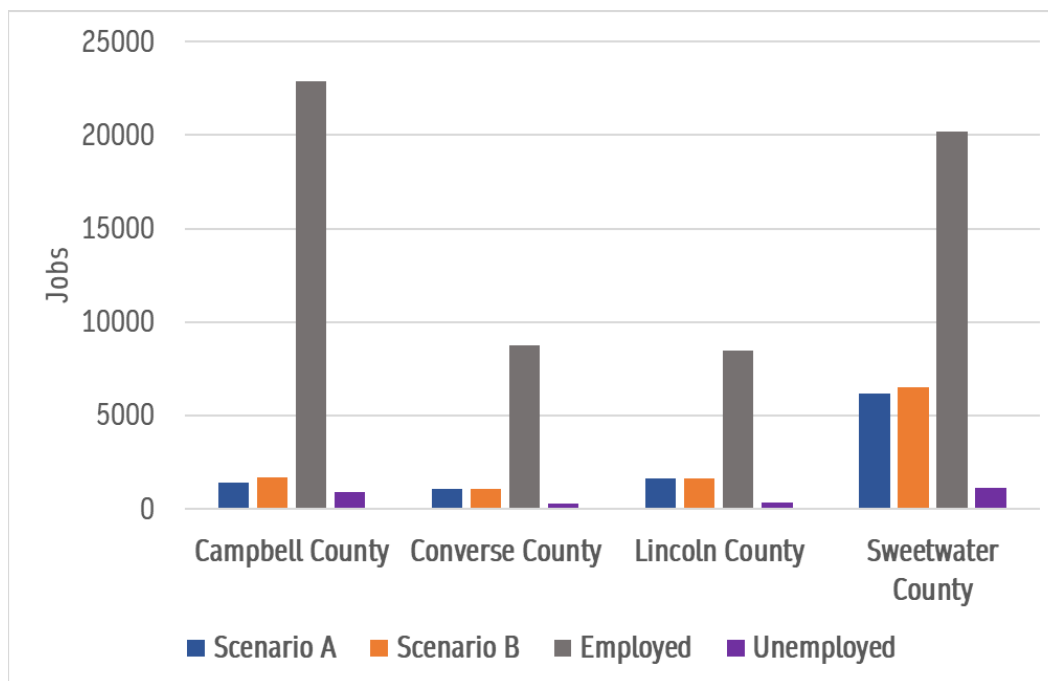


Figure 16: Average Long-Term Job Impacts By County (2026-2055)

This provides an indication of the continuing impacts in each county after the construction boom of 2022-2025. Figure 16 indicates that, over the long term, the CCUS scenarios have impacts that are very favorable for each county. For example, in Sweetwater County the jobs created by either CCUS scenario comprise 31% of the total January 2020 jobs in the county and five times the number of unemployed in that month.

The favorable job impacts of the CCUS scenarios contrast sharply with those of the Baseline IRP scenario in each county. Figure 17 shows the average annual net job differences in each county from 2026 to 2038, between the CCUS scenarios and the Baseline IRP scenarios. This figure illustrates that the CCUS scenarios annually generate far more jobs than the Baseline IRP scenarios. Specifically, over this period:

- In Campbell county, the CCUS scenarios annually generate about 630 more jobs than the Baseline IRP scenario,
- In Converse county, the CCUS scenarios annually generate about 510 more jobs than the Baseline IRP scenario,
- In Lincoln county, the CCUS scenarios annually generate about 1,600 more jobs than the Baseline IRP scenario,
- In Sweetwater county, the CCUS scenarios annually generate about 4,200 more jobs than the Baseline IRP scenario.

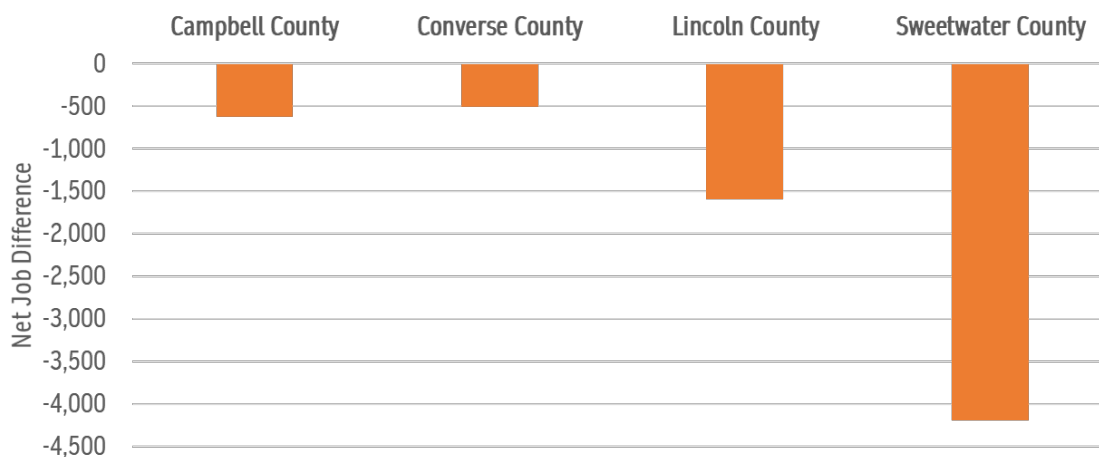


Figure 17: Average Annual Net Job Differences of Baseline IRP Scenario (2026-2038)⁸⁹

Implementation of the Baseline IRP scenarios instead of CCUS scenarios indicates that over the long term: 1) in Campbell County, the unemployment rate would be 5% to 10%; 2) in Converse County, the unemployment rate would be 5% to 10%; 3) in Lincoln County, the unemployment rate would be 20% to 25%; 4) in Sweetwater County, the unemployment rate would be 23% to 27%. Unemployment rates at these levels in all four counties would significantly impact personal income, coal related taxes for the coal plants, mines and production, ad valorem taxes, sales taxes, federal royalty payments and severance taxes.

Just as an example the following indicate the importance of coal mines and coal-fired power plants to Sweetwater county, much of which would not exist if these facilities close.⁹⁰

⁸⁹ Wyoming Department of Workforce Development and Management Information Services, Inc.

⁹⁰“Public Invited to Hearings On Investigation into PacifiCorp Coal Plant Shutdowns,” *Wyoming Digital News Collaboration*, January 24, 2020.

- In 2017, Jim Bridger Coal Mine, Black Butte Coal Mine, and the Jim Bridger Power Plant employed about 929 workers. New studies show that for each coal job created, three non-coal jobs were added to the economy.
- Coal employment added \$167,454,000 in wages to Sweetwater county alone.
- Coal employment supports, on average, 5,103 county residents – approximately 12% of the Sweetwater county population.
- Coal employees own approximately 1,394 single-family homes in Sweetwater county.
- Coal employees contribute approximately \$27,000,000 to the total assessed value of property in Sweetwater county.
- In 2019, the assessed value of all land, equipment, and infrastructure for the Black Butte coal mine and Jim Bridger coal plant and mine is \$242,757,938. Coal production from the Black Butte and Jim Bridger mines added another \$203,176,076. Coal related taxes for the assessed value of the coal plants, mines, and production in Sweetwater county in 2019 generated \$323,104,507 and \$22,248,955 in ad valorem taxes. Sweetwater county coal produced \$14,795,555 to Wyoming education funds.
- Sweetwater county received \$2,446,854 in sales and use taxes in 2019 from Jim Bridger and Black Butte coal mines.
- In 2018, Wyoming received about \$203 million in federal royalty payments from coal produced on federal land and about \$9.14 million of this amount was distributed to Sweetwater county. U.S. Department of the Interior, Natural Resources Revenue Data, Explore Data/Wyoming (last visited July 17, 2019), <https://revenuedata.doi.gov/explore/WY/>.
- Sweetwater coal mines paid \$12,549,259 in severance taxes to the State and Sweetwater county received a share of these taxes as well.
- Coal mines in Sweetwater county contributed \$724,911 to the Wyoming Office of State Lands.
- Sweetwater county received \$43,500,000 in Federal Abandoned Mine Land funds in 2018

The other counties reap similar benefits from these mines and power plants being operational. Without these mines and plants being in operation, a significant fraction of the state and county revenue will not exist.

This analysis shows that in Campbell county, the CCUS scenarios generate 1,400 more jobs annually than the Baseline IRP scenario. Similarly, in the Converse, Lincoln, and Sweetwater Counties, the CCUS scenarios, respectively, generate 1,100, 1,600, and 5,000 more jobs annually than the Baseline IRP scenario. This analysis shows that the Baseline IRP scenario could result in increased unemployment rates in the affected counties.

6 Regional Electricity and Environmental Market

6.1 Introduction

The objective of this analysis is to understand the current and projected market conditions in WECC—driven by the Baseline IRP scenario ⁹¹ where 2,521 MW of coal steam power capacity owned by PacifiCorp will be retired in Wyoming. This analysis focuses on the effects of the Baseline IRP scenario on reliability in WECC.

PacifiCorp⁹² owns about half of Wyoming’s coal fleet and is planning to retire most of it by 2038, some of which are early retirements. Table 9 shows the coal power retirements between 2020 and 2038, established in PacifiCorp’s 2019 IRP. This study examines the consequences of these retirements from an operation perspective and proposes an alternative portfolio that can be attractive from a cost and environmental perspective. (PacifiCorp, October 2019)

Table 9: PacifiCorp Wyoming Coal-Fired Power Plants⁹³

Station / Unit	Power Plant Output	Year of Retirement
Dave Johnston 1	99 MW	2028
Dave Johnston 2	106 MW	2028
Dave Johnston 3	220 MW	2028
Dave Johnston 4	330 MW	2028
Naughton 1	156 MW	2025
Naughton 2	201 MW	2025
Jim Bridger 1	351 MW	2023
Jim Bridger 2	356 MW	2028
Jim Bridger 3	349 MW	2037
Jim Bridger 4	353 MW	2037
Total Retirements 2020-2038	2,521 MW	

This analysis addresses the following:

- Balancing authorities (BAs) of Western Electricity Coordinating Council (WECC)
- The California cap and trade market and the Western Electricity Imbalance Market (EIM)
- CO₂ emissions, electricity prices and costs in PacifiCorp’s Integrated Resource Plan’s (IRP) preferred portfolio and an alternative portfolio with CCUS

⁹¹ PacifiCorp is a regulated electric utility that has two business units, Pacific Power and Rocky Mountain Power, and operates the largest transmission system in the EIM.

⁹² According to 2018 EIA 860 Form Data, Wyoming’s coal power capacity was 7,254 MW, and PacifiCorp owned or managed 4,598 MW (63%).

⁹³ Data from Table 8.18 from PacifiCorp’s 2019 IRP. (PacifiCorp, October 2019) The IRP also describes that Naughton unit 3 (280 MW) ended coal generation on January 30, 2019, and Wyodak (268 MW) is set to retire in 2039.

6.2 California Cap-and-Trade Market and the Energy Imbalance Market (EIM)

The EIM sets market conditions through a real-time market that dispatches resources every five minutes to correct electricity imbalances. EIM also operates a day-ahead market, a financial market where market participants purchase and sell electricity at financially binding day-ahead prices for the following day. EIM is operated by California Independent System Operator (CAISO). California enacted cap-and-trade legislation (CA AB32), which requires that allowances be purchased for every ton of CO₂ equivalent (CO₂e) emitted by generators that produce power using fossil fuels. These allowances, to an extent, are provided in a trade with in-state fossil fuel power plants providing them an advantage to dispatch electricity over fossil fuel power plants that do not reside in California.

6.3 WECC with a Focus on Wyoming and PacifiCorp

The Western Electricity Coordinating Council (WECC) is a not-for-profit entity tasked with supporting reliability and security of the Western Interconnection bulk power system (BPS). It spans 14 western states, 2 Canadian provinces, and northern Baja Mexico. Multiple states, balancing authorities (BAs), and service territories of independent system operators (ISOs) are included in the WECC service territory. There are 38 BAs within WECC, which are mostly electric utilities responsible for integrating resource plans, maintaining load interchange-generation balance within a BA area, and supporting interconnection frequency in real time.

CAISO is the largest BA in WECC, followed by BPA, and the Arizona Public Service Company. PacifiCorp East and WAPA Rocky Mountain Region, the two BAs in Wyoming, are the fourth- and fifth-largest BAs in WECC. Their combined generation, 94,000 GWh in 2018, is the 54 percent of CAISO's generation (175,000 GWh in 2018). Power from Wyoming power plants is therefore critical to maintaining reserve margins in WECC. In 2018, WECC generated 742,000 GWh, which consisted of 30 percent gas, 24 percent hydro, 21 percent coal, 10 percent of other generation, 8 percent nuclear, and 7 percent wind. The percentage of coal-fired generation in WECC has decreased over time and hydropower generation in WECC is more seasonal than other types of electric power generation.

6.3.1 Future Power Generation in WECC

To explain future power generation additions in WECC, this section highlights projections from different organizations, including EIA's Annual Energy Outlook (AEO) 2020, S&P Global, ABB PROMOD, ABB Velocity, and NERC's 2019 Long-Term Reliability Assessment (LTRA). Most of these datasets have values for up to 2038, and some are shown in Table 10.

Table 10: WECC Projections to 2038⁹⁴

Projection (MW)	EIA AEO2020 (Table 56)	ABB Velocity/PROMOD
Net Retirements 2020–2038, Nameplate	21,000	32,327
Net Additions 2020–2038, Nameplate	84,400	35,435
From Which, Intermittent Renewable Additions, Nameplate	34,700	25,463

⁹⁴ According to EIA AEO2020 and ABB/PROMOD.

The 2019 NERC LTRA presents information of resource mix changes planned through 2029⁹⁵. According to the 2019 NERC LTRA, the full WECC region will have additions throughout 2029 of solar and wind nameplate capacity totaling more than 300,000 MW. ABB Velocity/PROMOD projects in WECC a demand increase of 12,915 MW and future additions of solar, wind, and natural gas of the order of 31,771 MW. EIA also presents projections of demand for electricity and capacity additions in AEO2020. These values are presented annually for a 30-year period, up to 2050. The projections in the full WECC region show an increase in demand for electricity from 726 billion kWh in 2019 to 826 billion kWh in 2038, and an increasing nameplate generation capacity, from around 200 GW to 284 GW. According to EIA, coal power capacity in WECC will experience retirements of approximately 14 GW (14.5 GW retirements in 2019–2038 or 13.1 GW retirements in 2020–2038)⁹⁶.

6.3.2 Future Power Generation in Wyoming and PacifiCorp

PacifiCorp projects an increase in its obligations in the next 20 years⁹⁷. Table 11 highlights that in a 20-year period, the utility has a net additional summer obligation (plus reserves) of 206 MW, when compared with 2020.

Table 11: PacifiCorp Summer Obligations

	2020–2038	20-year increase
Load	10,426–12,192 MW	1,766 MW
Obligations ^A	9,877–10,059 MW	182 MW
Obligations plus reserves ^B	11,184–11,390 MW	206 MW

Note: Values are from tables 8.19 and 8.20 of PacifiCorp's 2019 IRP

^A Obligation is the total electricity demand that must be served and is defined in the IRP as forecasted retail load - private generation - interruptible contracts - energy efficiency

^B Planning reserve margin of 13 percent

The Baseline IRP scenario establishes the retirement of 5,434 MW, from which 4,486 MW are coal retirements (2,043 MW of these are labeled as “early coal retirements”)⁹⁷. These projections are based on the nameplate capacity in 2019.

Despite the retirements, the utility expects to add 13,486 MW, from which approximately 3,100 MW and 5,700 MW correspond to new wind and solar (all of which has co-located storage), respectively, 1,365 MW of battery stand-alone, and 1,873 MW corresponds to new gas nameplate capacity. The utility also counts 2,315 MW of new energy efficiency and 444 MW of demand response equivalent nameplate capacity.

Figure 18 shows these additions and retirements by fuel type. In summary, PacifiCorp is replacing 5,434 MW with new resources that total 13,486 MW from which 10,700 MW are generation capacity (physical generation assets), 1,365 MW are stand-alone storage resources and 2,800 MW are new demand response and energy efficiency resources.

⁹⁵ NERC, "NERC Long-term reliability assessment 2019," NERC, December 2019.

⁹⁶ EIA, "Annual Energy Outlook 2020," 2019. [Online]. Available: <https://www.eia.gov/outlooks/aeo/>. [Accessed 27 February 2020].

⁹⁷ PacifiCorp, "2019 Integrated Resource Plan Volume I and Volume II," PacifiCorp, October 2019.

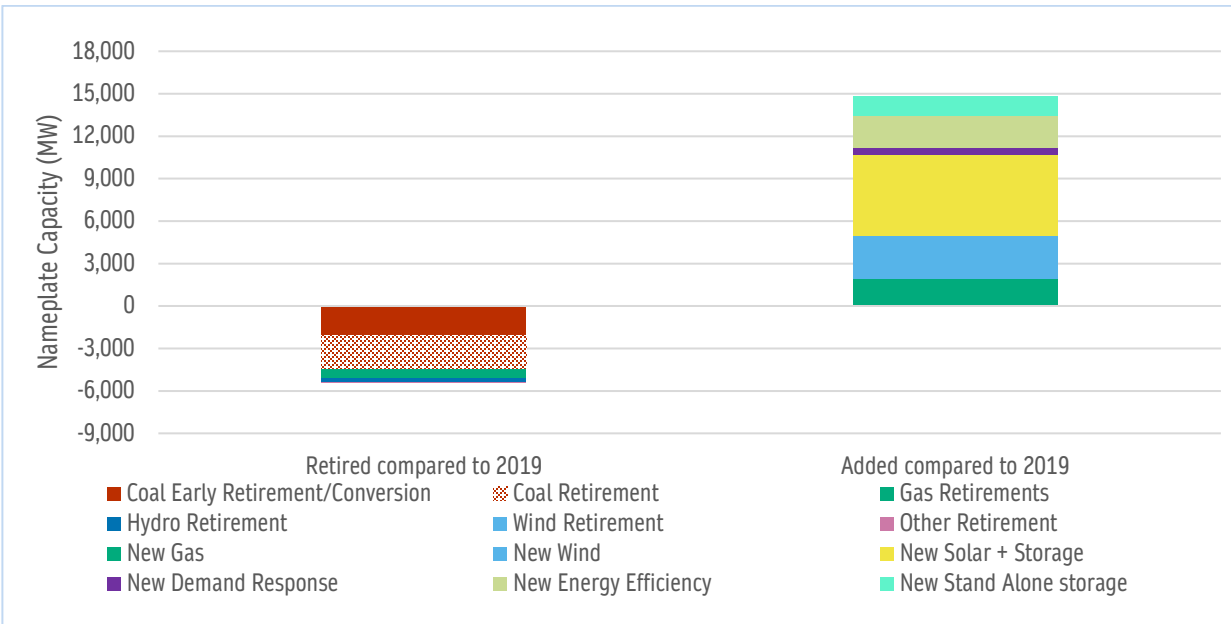


Figure 18: PacifiCorp Planned Retirements and New Generation Capacity

In terms of their capacity balance, PacifiCorp shows that they are able to meet their coincidental summer peak plus reserves for most of the years, with a relatively small capacity balance deficit starting in 2028. Their capacity balance is established as

$$\text{Capacity Balance} = \text{Existing Resources} + \text{Available Front Office Transactions} - \text{Obligation} - \text{Reserves}$$

where

$$\begin{aligned} \text{Existing Resources} &= \text{Thermal} + \text{Hydro} + \text{Solar} + \text{Wind} + \text{Firm Purchases} + \text{Qualifying Facilities} \\ &+ \text{Existing Demand Response} - \text{Firm Sales} - \text{Non_owned Reserves} \end{aligned}$$

$$\text{Obligation} = \text{Load} - \text{Interruptible Contracts} - \text{New and Existing Energy Efficiency}$$

$$\text{Reserves} = \text{Obligation} \times \text{Planning Reserves Margin}$$

Figure 19 highlights the changing resource mix in PacifiCorp through the next 10 and 20 years (data from PacifiCorp's IRP). The small obligation increase (i.e., the slope of the orange line) is expected to be met through significant capacity additions.

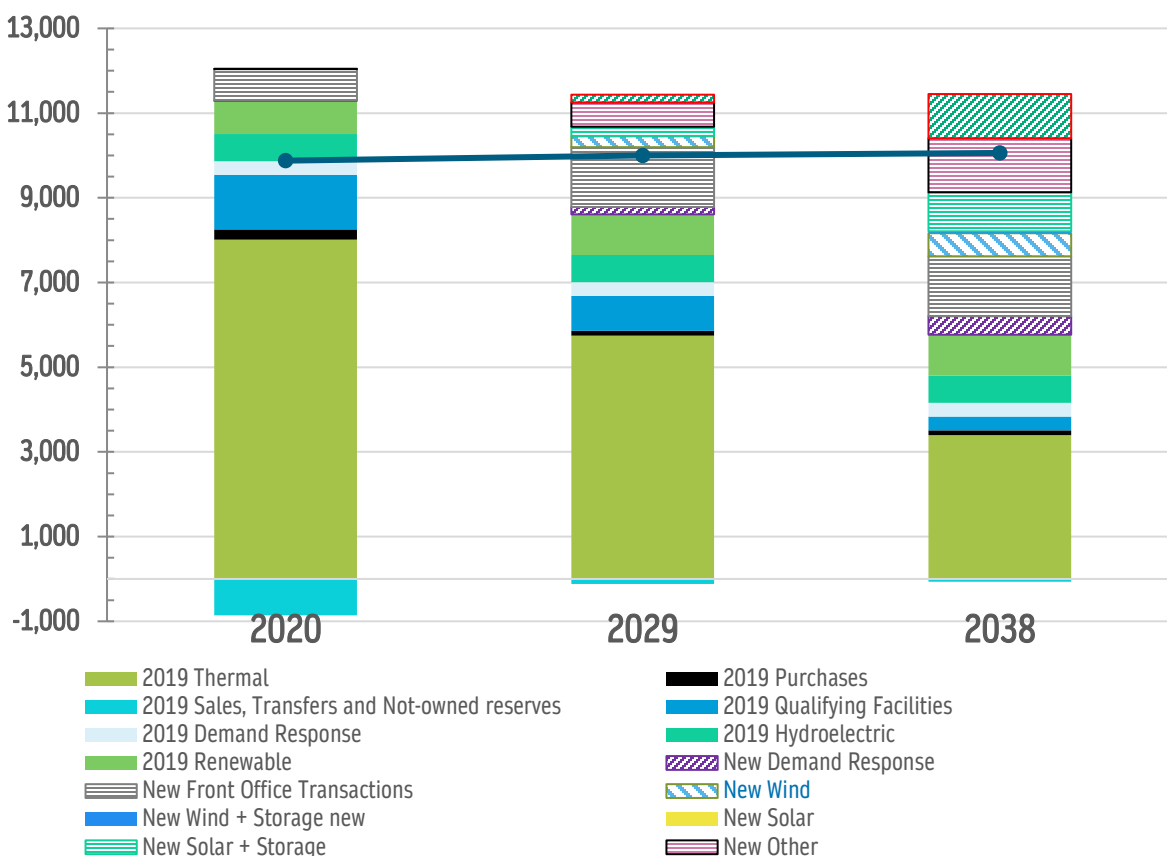


Figure 19: Summer Capacity of the IRP preferred portfolio (MW)⁹⁷

The utility highlights that these additions will require significant investments both in terms of generation resources and transmission lines. They indicate that the associated costs are \$17.3 billion, of which \$14.5 billion are for the expansion of generation resources, and \$2.8 billion are for transmission expansion.

6.4 Dispatch Analysis Using PROMOD

The analysis reviewed the Baseline IRP scenario and the proposed costs of the expected additions in the system. In short, the Baseline IRP scenario is requesting approximately \$17.34 billion to meet a summer peak load of 1,766 MW in the next twenty years (or an obligation plus reserves increase of approximately 208 MW, equivalent to 2 percent of the total system summer peak capacity). Resource additions and resource retirements under the Baseline IRP scenario are 14,851 MW and 5,434 MW, respectively, coming to net resource additions of 9,417 MW. Out of the 14,851 MW of additions, 8,854 MW correspond to wind and solar capacity additions.

6.4.1 Assumptions

The model study period is 2020–2038, to mirror the horizon in the Baseline IRP scenario, and the region considered in the U.S. WECC territory. The Baseline IRP scenario includes the retirement of 4,212 MW of coal power by 2038 in PacifiCorp's territory. The scenarios are summarized in Table 12.

The CCUS scenario has the following differences compared to the baseline:

- All coal power units in Wyoming owned by PacifiCorp (with a capacity equal to 2,521 MW) that are listed for retirement operate normally over 2020-2025, and with a CCUS retrofit over 2026-2038, with the exception of Dave Johnston 1-2 (combined 205 MW), which retire in 2028 as scheduled in the Baseline IRP.
- An additional unit in Wyoming that is not listed for retirement before 2038, Wyodak, is retrofitted as well with CCUS and operates normally in 2020-2025 and with a CCUS retrofit over 2026-2038.
- CCUS was added to each unit in the selected plants, under a direct retrofit, and unit statistics in the dispatch model were updated to reflect parasitic load, heat rate changes, unit costs, and emissions rates.

Table 12: PROMOD Scenarios for WECC Analysis

Scenario	PacifiCorp Territory ^A	Rest of WECC ^B
Baseline	IRP preferred portfolio	PROMOD's forecast module
CCUS	Coal units retrofitted with CCUS starting in 2026: Dave Johnston 3-4, Jim Bridger 1-4, Naughton 1-2 and Wyodak. Dave Johnston 1-2 retire in 2028	PROMOD's forecast module (equal to baseline)

^A PacifiCorp serves 1.9 million customers in the United States, through Pacific Power, in Washington, Oregon, and California, and Rocky Mountain Power in Idaho, Wyoming, and Utah

^B Rest of WECC consists of all other WECC regions in the United States

The Baseline IRP scenario in Table 12 will be used to compare against the other scenarios in this analysis. The Baseline IRP scenario used standard model updates, including certain capacity changes in all zones, and uncertain capacity additions, in all WECC zones except PacifiCorp zones. Thermal unit retirements described in the IRP were added to coal and natural gas plants in the model. Uncertain capacity build-out in the PacifiCorp zones was replaced with unit additions described in the Baseline IRP, including natural gas, wind, and solar units.

Scenario 2 involves retrofitting four Wyoming coal power plants with CCUS as defined in Section 4 of this report.

6.4.2 Methodology

The baseline PROMOD scenario was modeled by comparing the net load required peak (peak load minus available demand response) to the available generating capacity. The expected summer peak increase for the full WECC region from 2019 to 2038 is 24,916 MW. Because PROMOD does not add specific generation when load exceeds capacity, additional generating capacity was added based on current queue and the required planning RMs for each NERC area defined in the LTRA. The capacity balance for the studies is defined as:

$$\text{Capacity balance} = \text{Existing resources} - \text{Existing demand response} - \text{Obligation}$$

where existing resources include thermal, hydro, solar and wind, and obligation refers to the load.

In the study, wind and solar generators were derated based on NERC subregion LTRA factors. All other units were rated at nameplate capacity.

Regional LMPs, emissions, capacity factors, fuel usage, and unit operating margins for the three scenarios (Baseline, Scenario 1, Scenario 2) were obtained from dispatch modeling using PROMOD. The sensitivity of results to CO₂ pricing was also modeled. Because of the way plant units were aggregated to BAs in the model, results were aggregated at three levels: the whole of WECC, the Wyoming BA area, and the Wyoming, Utah, and Idaho BA areas aggregated together.

6.4.3 Dispatch Analysis Results

As can be seen in Figure 20, addition of generation labeled “Uncertain” is sufficient to maintain minimum planning RMs for all WECC subregions in 2038. The additions are labeled uncertain since this study assumed the generation mix of future resources to be added to achieve minimum planning RMs in all regions. It is possible that other actions will be taken to prevent violation of the NERC prescribed planning RMs.

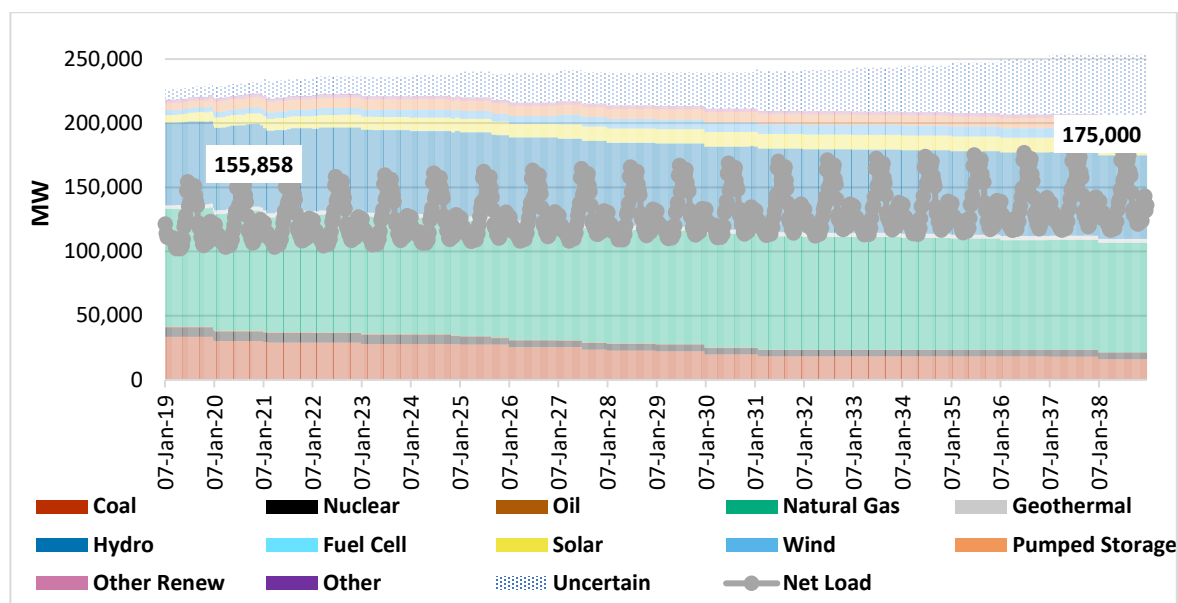


Figure 20: Capacity Balance for the Baseline IRP Scenario

When natural gas generation was set to reflect a historical average 35 percent capacity factor (ABB, 2019) and the net load is much closer to the total available capacity, the retirement of coal units, or loss of intermittent resources cause the expected load to exceed the available capacity (*see* Figure 21).

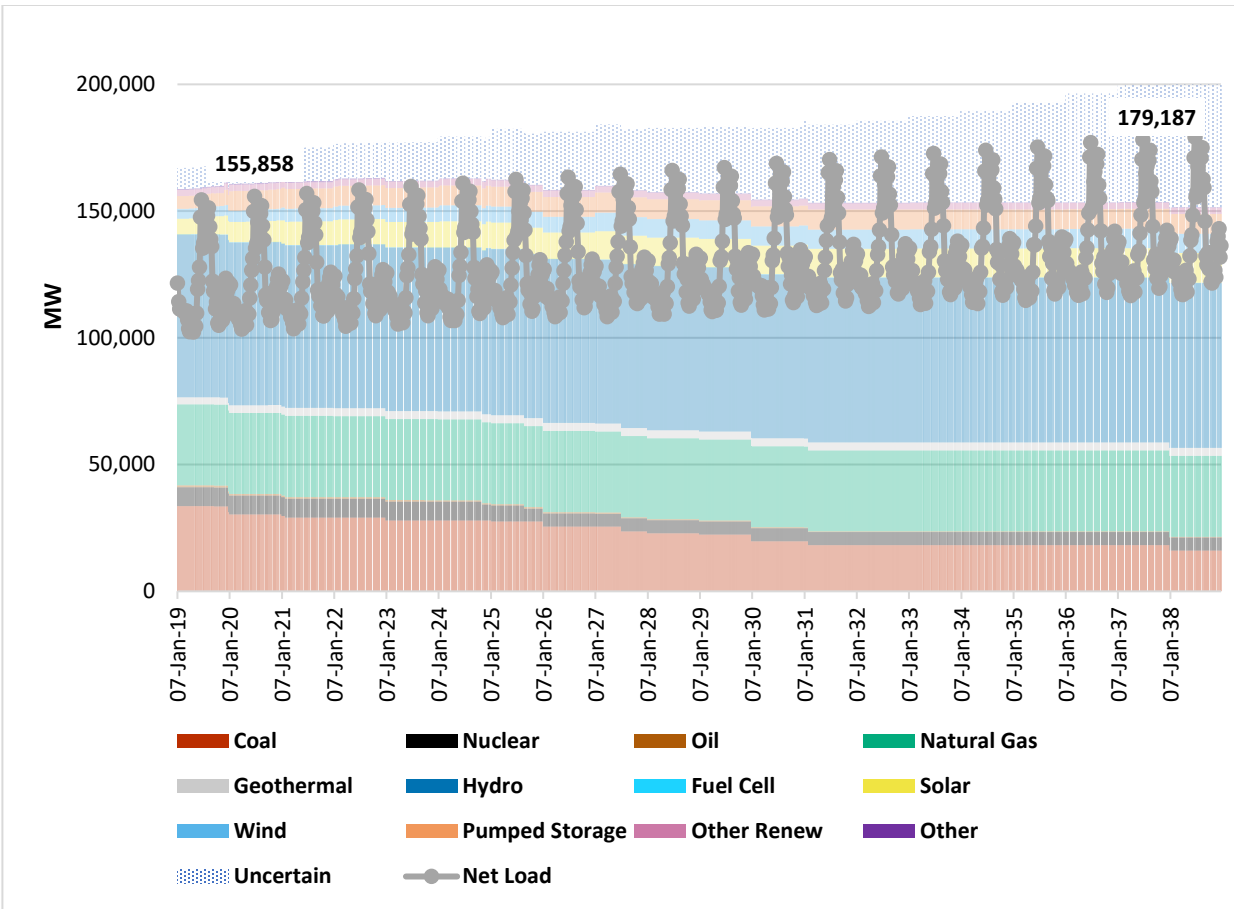


Figure 21: WECC Available Generation Capacity with Historical Natural Gas Capacity

Emissions reductions from adding CCUS are fewer than the associated CO₂ emissions for the Baseline IRP scenario which includes the retirement of coal plants and installation of a range of new power generation facilities. This is highlighted in Figure 22, showing CO₂ emissions in Wyoming through 2038.

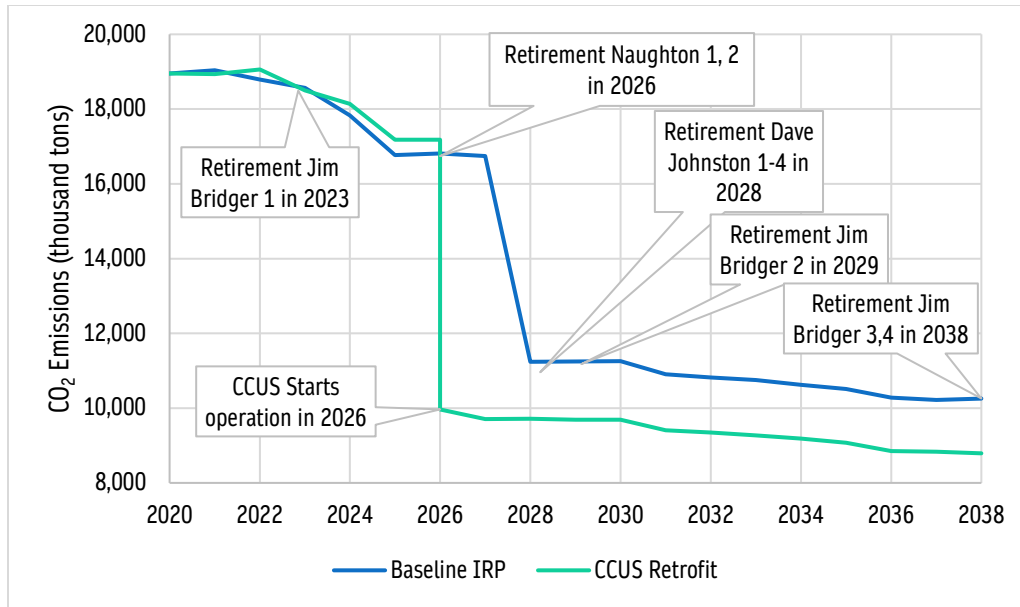


Figure 22: Wyoming CO₂ Emissions

Figure 23 shows the amount of CO₂ captured through the CCUS process for the 4 plants (9 units), showing that including CCUS with these plants would result in significant CO₂ capture.

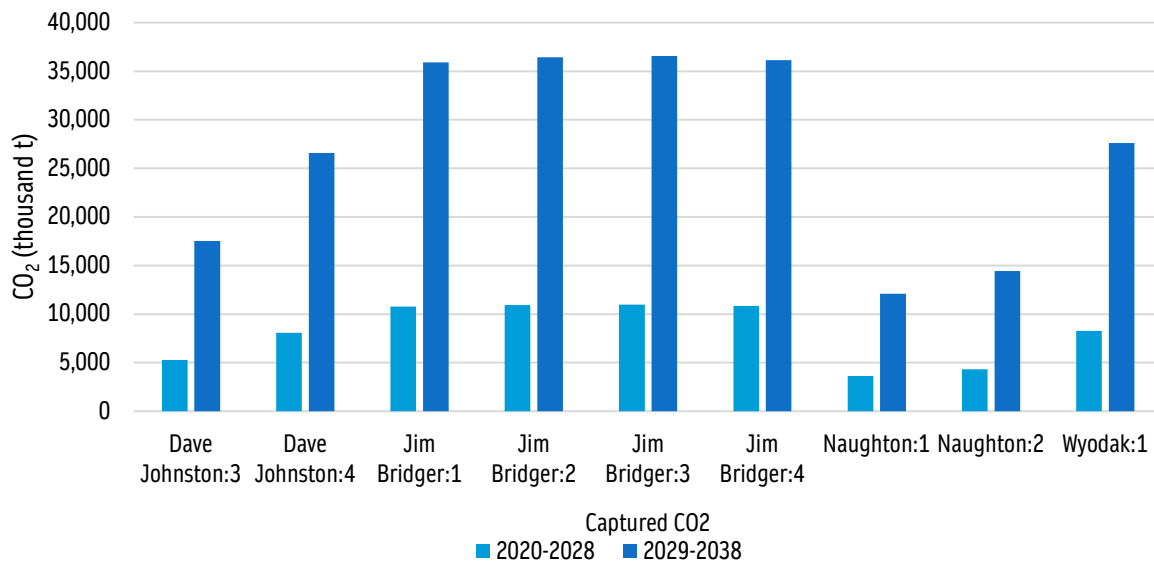


Figure 23: Captured CO₂ Emissions with CCUS

Results from the economic dispatch analysis using PROMOD show very little difference in the LMP through 2026 between the Baseline IRP scenario and CCUS scenario. The changes in on-peak locational marginal prices (LMPs) from the Baseline IRP scenario are shown as box plots in Figure 24. The median on-peak LMP for the CCUS scenario is almost the same as the median on-peak LMP in the baseline (this is shown as the line in the 'box'). The average on-peak for the CCUS scenario is 0.4% more than the on-peak LMP from the baseline scenario (considered to be within the margin of error of the PROMOD model). Installing CCUS retrofits does not have a significant effect on the on-peak LMP in the period 2020 to 2038. The median on-peak LMP for the CCUS scenario from 2020 to 2025 is also similar to the median on-peak LMP from 2026 to 2038.

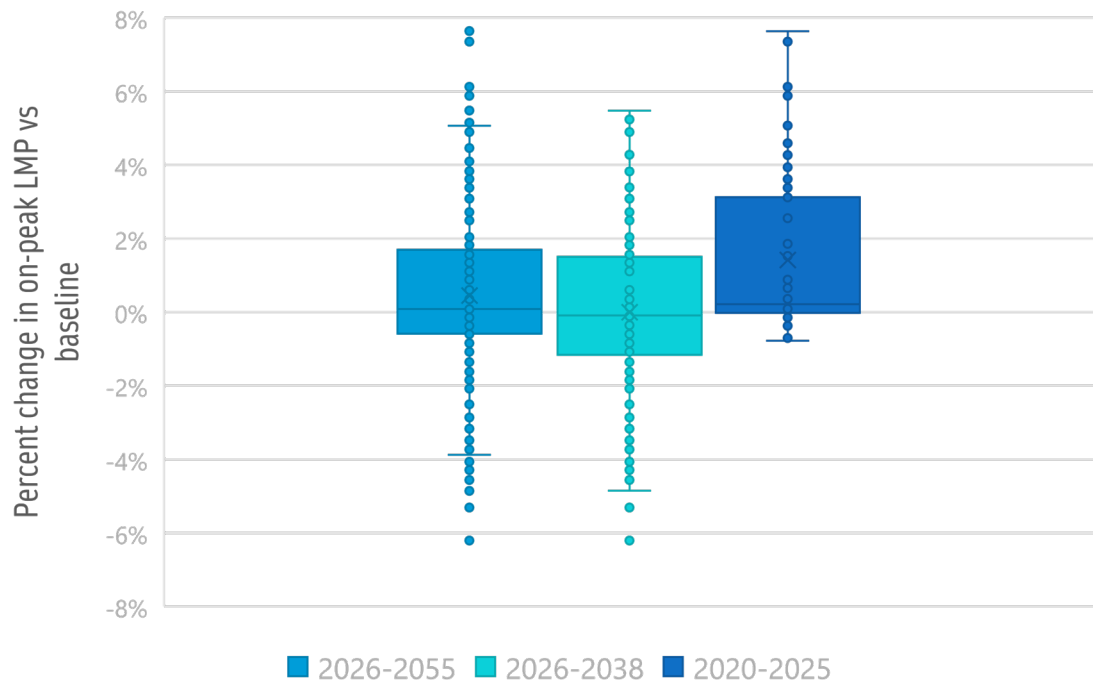


Figure 24: Change in On-Peak LMP vs Baseline IRP Scenario

Figure 25 shows coal and natural gas use by dispatch, across all WECC for the Baseline IRP scenario and CCUS scenario. In both cases, both fuels show a decrease from 2020, with natural gas leveling off in 2025, and coal continuing its decline as more units retire. For the CCUS scenario there is an increase in coal use of about 4,000 tons (3,629 tonnes) in 2029 and a reduction of 10–50 Bcf natural gas compared to the Baseline IRP scenario.

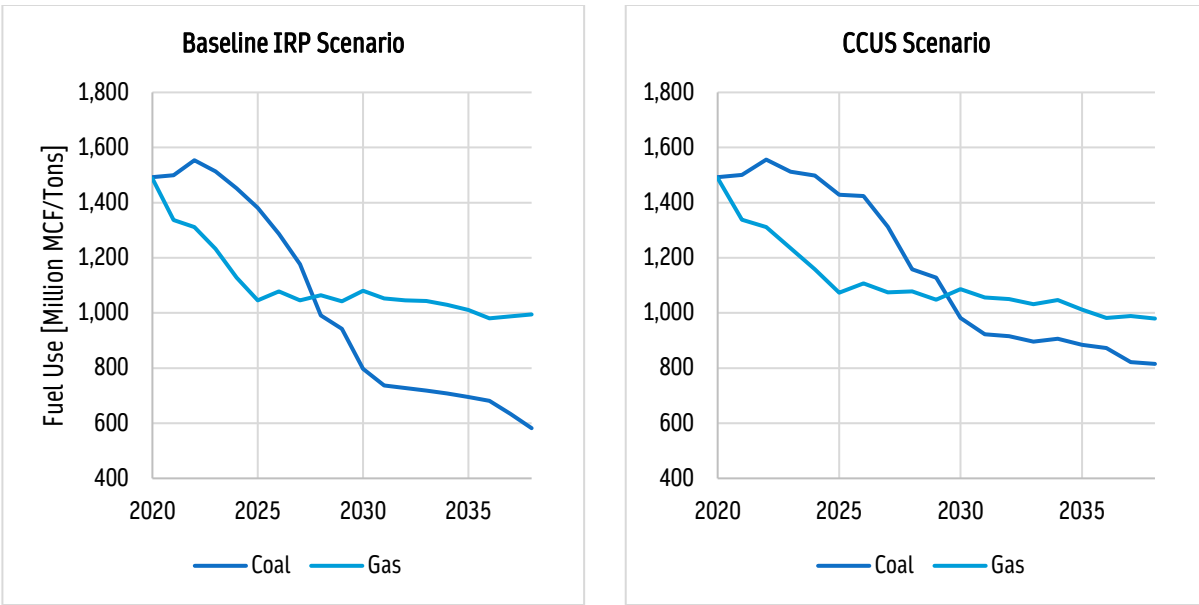


Figure 25: Comparison of Fuel Consumption

6.4.4 Scenario Comparison

The Baseline IRP scenario is heavily focused on the integration of wind, solar, and energy storage. Only a net addition of 1,200 MW of new gas capacity is considered. So, although the obligations plus reserves in the next 20 years are not expected to increase significantly (an additional 200 MW summer peak obligation, in a 10,000 MW summer peak system, i.e., approximately a 2 percent increase of obligations plus reserves), the utility has to add 2.5 MW per MW that retires to maintain its capacity and energy balances.

The heavy emphasis on replacing a large share of the coal power fleet with wind and solar resources results in relatively high resource investments. In total, the utility forecasts \$14.5 billion in resource investment. There are important and significant repercussions on rate adjustments in retail tariffs that will be considered for the approval of the IRP. If these investment costs are fully recovered through electricity tariffs, and are assumed to be spread uniformly through PacifiCorp's 1.9 million customers, over 20 years, the electric bill would need to increase on average \$38/month for each consumer to pay off the IRP preferred portfolio expenses. In contrast, the Scenario 2 portfolio is paid off with an increase of \$31/month per customer, over the same period. According to Form EIA-861, the average Wyoming residential bill was \$94.9/month in 2018. [3] Assuming this is representative of PacifiCorp residential customers in Wyoming, the \$7/month difference between the two portfolios would represent approximately a 10 percent higher bill under the baseline scenario.

The heavy emphasis on integration of intermittent renewable energy also requires significant transmission investment. The utility forecasts \$2.8 billion in transmission projects to integrate the new resources. Issues concerning the operation, maintenance, and security of this new infrastructure should be clearly established. The IRP preferred portfolio requires more than \$17.3 billion in investments. Variable renewable energy (VRE) investments in the CCUS scenario are lower than in the Baseline IRP scenario due to the availability of clean, firm energy from coal power plants with CCUS. The resource mix of the scenarios are provided in Table 13.

Table 13: Scenario Resource Mix (Compared to 2019)

Generation Technology (MW)	All PacifiCorp, 2019–2038			
	Baseline IRP Scenario		CCUS Scenario ^A	
	Retired	Added	Retired	Added
Coal	-4,486	-0	-1,965	0
<i>Early Retirement/Conversion ^B</i>	<i>-2,043</i>	<i>N/A</i>	<i>-1,199</i>	<i>N/A</i>
<i>In Wyoming ^B</i>	<i>-2,521</i>	<i>0</i>	<i>0</i>	<i>0</i>
Gas	-593	1,873	-593	1,873
Hydro	-282	0	-282	0
Wind + Solar with Storage	40	8,854	40	4,282
<i>Wind</i>	<i>-40</i>	<i>3,109</i>	<i>-40</i>	<i>1,119</i>
<i>Solar with Storage</i>	<i>0</i>	<i>5,745</i>	<i>0</i>	<i>2,654</i>
Other	-33	0	-33	0
Demand Response	0	444	0	230
Energy Efficiency	0	2,315	0	1,354
Stand-Alone Battery Storage	0	1,365	0	0
Total	-5,434	13,486	-3,118	7,738 ^C

^A With CCUS in Wyoming Plants Dave Johnston 3-4, Naughton 1-2, Jim Bridger 1-4, totaling 2,316 MW (installed capacity reported in IRP). Wyodak (268 MW) is the only coal power plant that remains in Wyoming after 2038 and scheduled to retire in 2039.

^B The sum of these two categories does not correspond to the total coal. Some Wyoming coal retirements are labeled as early retirements.

^C Scenario 2 assumes the same average of additions/retirements in the *IRP preferred portfolio*, equal to 2.5 MW added/MW retired. The technologies selected to meet 7,738 MW were chosen by merit order based on costs.

This analysis finds that if CCUS is added to Wyoming plants Dave Johnston 3-4, Naughton 1-2, Jim Bridger 1-4, the 2,316 MW listed as coal retirements in Wyoming plus Wyodak, total additional resources will be less than those under the Baseline IRP scenario. Under the Baseline IRP scenario, additions are 13,486 MW, and under the CCUS scenario are 7,738 MW. This level of additions was estimated using a 2.5 MW-retired/MW-added ratio, equal to the average ratio of the Baseline IRP scenario (without considering stand-alone battery additions), with a total under the CCUS scenario of $2.5 \times 3,118 \text{ MW} = 7,738 \text{ MW}$.

From those 7,738 MW additions in the CCUS scenario, 4,282 MW correspond to new wind and solar resources. This corresponds to reducing by 5,081 MW wind and solar additions, compared to the Baseline IRP scenario. The resources composing the 7,738 MW were selected based on a ranking of total investment costs, as the sum of capital costs plus transmission investment costs. The marginal resource under the CCUS scenario is a Utility Solar

plus Storage resource with a resource plus transmission cost of \$1,685/kW. All resources with a lower cost were included and all resources with a higher cost were excluded.

In the Baseline IRP scenario, the total investment is estimated in \$17.34 billion. In the CCUS scenario, it is estimated in \$14.06 billion. This corresponds to savings of \$3.28 billion.

From an environmental perspective, although CCUS does not replace 100 percent of the emissions associated with coal power generation, the state-of-the-art technology captures 90 percent. Consequently, average emissions captured under the CCUS scenario from coal power generation are approximately 23.7 million tons per year (TPY) (21.5 million tonnes per year) of CO₂. When comparing the two scenarios (not only the emissions from coal power retirements), the CCUS scenario removes an additional 109 million tons (100 million tonnes) over 2019–2038. In other words, the CCUS scenario is economically more attractive and has associated fewer emissions over 2019–2038 than the Baseline IRP scenario. The total emissions over 2019–2038 for the Baseline IRP scenario are 568 million tons (515 million tonnes), and 459 million tons (416 million tonnes) for the CCUS scenario.

From an environmental perspective, the Baseline IRP scenario is in line with the utility's CO₂ emissions reduction overall strategy.⁹⁸ On the other side, the CCUS scenario achieves large economic savings, and higher emissions removed, which results in a more cost-effective portfolio. In fact, the CCUS scenario avoids 403 million tons (366 million tonnes) in the PacifiCorp territory over 2019–2038 or avoids 109 million tons (100 million tonnes) more than the Baseline IRP scenario, and saves \$3.28 billion. This results in an average cost-effective metric of \$35/avoided ton (\$32/avoided tonne) in The CCUS scenario over 2019–2038, and \$59/avoided ton (\$53.5/avoided tonne) in the Baseline IRP scenario.

⁹⁸ The utility is reducing its carbon emissions through three initiatives: PacifiCorp's participation in EIM, expansion of wind and solar resources and transmission, and Regional Haze compliance that capitalizes on flexibility.

7 Appendices

7.1 Capacity factor for W A Parish CO₂ capture project (Unit 8)

There exists a possibility that a power plant retrofitted with CCUS could operate at a lower capacity factor because of technical/process contingencies associated with operating the CO₂ capture equipment, and the manner in which the CO₂ capture unit is interfaced with the rest of the power plant. On the other hand, because CCUS results in both 45Q tax credits and revenue via sale of CO₂, power plants also have an incentive to operate the CCUS retrofitted units at a higher capacity factor. One example of a power plant retrofitted with CO₂ capture is the Petra Nova CO₂ capture project (Unit 8 at the W A Parish power plant). LTI examined hourly EPA CEMS data from Unit 8 at the W A Parish power plant (Petra Nova CO₂ capture project) to calculate the capacity factors before and following the CCUS retrofit.

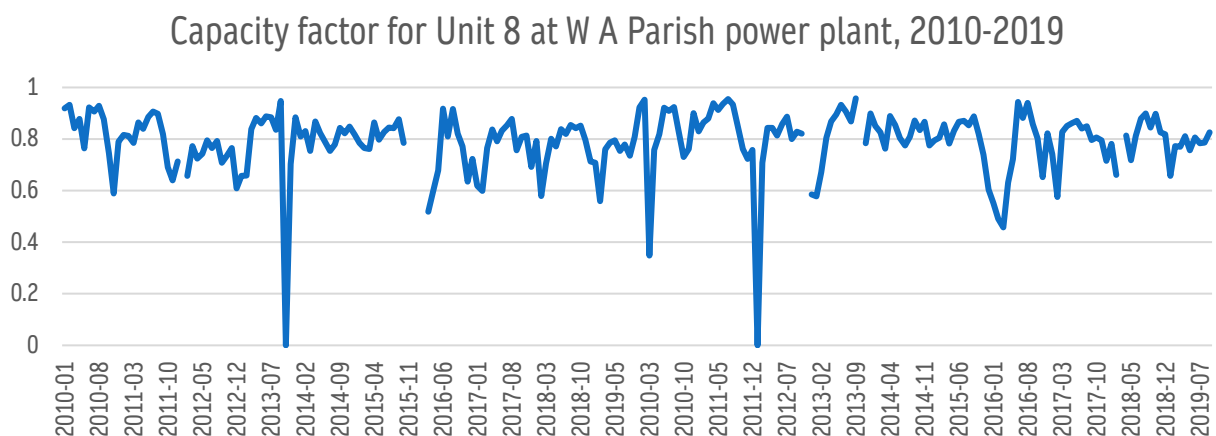


Figure 26: Capacity factor for the Petra Nova CCUS project

The statistical analysis of the capacity factor data for Unit 8 from 2010 to 2019 indicated that there is no statistically significant difference in the capacity factor pre-, post-CO₂ capture retrofit. LTI therefore concluded that the CCUS retrofit was not expected to significantly affect the availability of the plant.

7.2 Details of the EOR modeling study

Detailed simulations were performed using a modified version of the CO₂ Prophet Model and using an extensive database of oil reservoirs that are currently undergoing CO₂ floods or which have the potential to start floods if CO₂ is available (ARI 'Big Oil Fields Database').

The Big Oil Fields Database includes:

- Volumetrically consistent information on the original oil in-place endowment in each oil reservoir.
- Updated information on cumulative oil production plus remaining oil reserves for each oil reservoir, providing rigorous data on remaining ("stranded") oil that is the target for CO₂ and other EOR methods.
- Reservoir-specific data on key reservoir properties that significantly influence the performance of a CO₂-EOR project, including swept-zone oil saturation, oil viscosity, reservoir heterogeneity (Dykstra-Parson's Coefficient), oil gravity, reservoir temperature and reservoir pressure.
- Reservoir-specific data on the existing field infrastructure and activities that influence the development costs and economic performance of a CO₂-EOR project, including: active and shut-in producing wells, active and shut-in injection wells, and volumes of water injection and production.
- Reservoir-specific data on any CO₂-EOR activity already underway, including cumulative EOR production, the latest EOR production rate, and estimated remaining EOR reserves.

The Big Oil Fields Database contains information of the type described above for 89 oilfields in Wyoming that have the technical potential for CO₂-EOR. These oilfields were analyzed using the framework of a CO₂-EOR technoeconomic model derived from a version of the well-known model called CO₂ PROPHET, which was modified and calibrated to real-world CO₂-EOR project data. USGS describes the model in their report 2017-5062-B⁹⁹.

The CO₂ Prophet model was used to identify a smaller subset of fields from among these 89 candidate fields that, if they had a reliable CO₂ supply, would be capable of profitably commencing CO₂-EOR floods while paying a supplier for that CO₂. The standard for "profitability" in this analysis was a pre-tax return of at least 15% for equity investors. In other words, the net-present value at a 15% discount rate of the investments funded by equity investors and the cash returned to equity investors from oilfield-distributable earnings is required to be more than zero.

The CO₂ Prophet Model analysis includes required outlays for construction of surface facilities to process gases and liquids produced from extraction wells, and to reinject (CO₂ and water) into injection wells, newly-drilled and reworked wells in the subsurface, purchases of CO₂, and ongoing leasehold operating expenses. Revenues are estimated from produced oil, less royalties, severance, and ad valorem. The outputs of the CO₂ Prophet Model analysis include the quantity of CO₂ injected each year, the relative proportion of CO₂ comprised of recycled versus newly purchased CO₂, and crude oil production.

⁹⁹ USGS "Using CO₂ Prophet to Estimate Recovery Factors for Carbon Dioxide Enhanced Oil Recovery ", Scientific Investigations Report 2017-5062-B, p. 2. https://pubs.usgs.gov/sir/2017/5062/b/sir20175062_chapb.pdf

The parts of the Big Oil Fields Database which were provided to SimCCS were:

1. The average CO₂ demand per year for a 30-year project (MT/year)
2. The break-even price a field could pay for CO₂ and still make a 15% profit (2020USD/MT)
3. The field's geographic location (latitude, longitude)
4. A unique two-digit identifier (An integer between 1 and 89)
5. Capex incurred by a field starting a CO₂ flood (2020USD)
6. O&M costs of that field continuing the CO₂ flood as a thirty-year project (2020USD/year)

7.3 Design and technical aspects of SimCCS

SimCCS is a CO₂ capture and storage cost optimization program that aids scientists, energy planners, businesses, and policy makers. As these actors contemplate applying CO₂ capture at scale, they are faced with the challenge of estimating the costs and feasibility of capturing from multiple CO₂ sources, then transporting over a to-be-built network of pipelines to reach numerous potential CO₂-EOR sites or saline storage sites. SimCCS can use geospatial information to optimize nearly limitless possible pipeline configurations connecting various combinations of sources and sinks. For each of these possible scenarios, SimCCS can estimate profits or losses by component and as a total. Most of the endpoint costs and revenues are supplied by users: in this case, CCUS retrofit costs from the CCRD, EOR volumes and revenues from CO₂ Prophet, and saline storage volumes and costs estimated via SCO₂T were used as inputs. SimCCS's built in network transportation costs were adjusted to 2020USD, and cost-surface multipliers for the specific topography of the pipeline routes were used.

The objectives in SimCCS included:

1. Performing the requested pair of analyses. DOE identified these two after being shown a variety of example analyses showcasing the various scenarios SimCCS could run.
2. Providing some context for those requested analyses by running supplemental analyses. These supplemental analyses were oriented towards minimizing costs to show an outright profit. Some achieved this by being less ambitious and capturing lower volumes of CO₂, others by eking a greater profit out of CO₂-EOR sales, and still others by resilience to market changes which could reduce risk and allow a more finely-tuned system. The goal in these supplemental analyses was to avoid significant costs to electricity ratepayers.
3. Processing the system configurations generated in these scenarios to aid in the task of estimating local jobs and economic impacts. Post-processing work was done by EORI and CEGR to divide up capex and opex of physical facilities and employment county-by-county for further analysis.

7.3.1 Design and Technical Aspects of SimCCS

SimCCS was built by Richard Middleton and Jeff Bielicki and is maintained by Team SimCCS (Middleton and Bielicki, 2009). Improvements since SimCCS was first programmed include a Java GUI. This GUI helps the user formulate, submit, and review a linear optimization problem to a solver such as IBM's CPLEX. Sinks, transport, and storage components can all be customized with a text editor and this GUI. In practice the transport component is the least customizable because it requires a precomputed cost surface, and a linearization of the equation linking cost to the amount of CO₂ the pipeline can transport (chiefly the pipe diameter). These typically are built by members of Team SimCCS for each new geographic location where there is interest in using SimCCS.

There are two modes in SimCCS which pose slightly different optimization problems to the linear-program-solver (in this case, CPLEX): Cap, and Price. In the Cap-mode SimCCS is told it must store a user-supplied quantity of CO₂ and should find the cheapest way to store that quantity. In Price-mode the restriction on quantity is lifted, and SimCCS is told it may store as large or small a quantity of CO₂ as necessary to result in maximum profit (represented in-program as negative costs). Accordingly, in Price-mode some part of the system must produce profit or avoid a cost (such as 45Q, green electron arbitrage, a price-on-carbon, cap-and-trade, etc.). If there is inadequate profit, the underwhelming conclusion of SimCCS's Price-mode optimization is that "no system makes a profit, and accordingly nothing should be built".

One of SimCCS's most notable strengths is its ability to run on a desktop computer. The runtime of the problem-solving step in SimCCS expands as the product of two polynomials: sinks and sources. This means that reasonable runtimes are possible with one sink and many sources or one source and many sinks. Runtimes become longer, with very high memory usage, when the number of sinks and sources are more equal. In the runs described here the number of sources was capped at 4, and the number of sinks was as large as 56 EOR fields and 141 Saline sinks. This was enough to make a full run of 4 by 56+141 infeasible. Accordingly, when EOR fields were run, saline sinks were reduced to 20 aggregated sinks representing a mean location, mean unit cost, and summed volume for each formation in a basin. This innovation allowed reasonable runtimes of about one hour in "Cap-mode", and slightly longer in "Price-mode" on a modern 2019 desktop computer.

7.3.2 Analyses Run Using SimCCS

The overall economic framework was actor agnostic. It did not matter if different business entities owned the source, transport, and sink components, or if they were all owned by one entity. This means that when a model shows a profit or a loss, some actor involved would have that profit/loss, but exactly who it would depend on contract details not within this study's scope. Consequently, if SimCCS shows a system as breaking even, it is conceivable that one participant would be profiting and another losing.

One exception to the above actor-agnosticism was market-clearing. In all scenarios (except the last one described in section 6.3), the value of the CO₂ sold to CO₂-EOR was the market-clearing price: that is, all CO₂-EOR operators within a particular pipeline network would pay the same competitively determined market price. That competitive market price was often much lower than what they would be willing to pay for CO₂ delivered on a bespoke capture and transport system which served only their field and thus had no competitive market effects.

In all cases, carbon capture source information was based upon parameters set by, and CCUS plant retrofit cost analysis. There were a total of nine coal units under consideration: Jim Bridger units 1, 2, 3, and 4; Dave Johnson units 3&4; Wyodak (single unit); and Naughton units 1&2. In all analyses it was assumed that no unit would exceed 90% capture of flue gas carbon dioxide that otherwise would be emitted. The 90% fraction represents the typical fraction of CO₂ captured when flue gases are processed in amine capture units of the type being analyzed in the study. At 90% capture efficiency the four power stations in this study provide 23.67 million MT/year of CO₂ for CCUS. In two non-requested cases described in section 6.3 units were allowed to capture less than this 'full' 90% capacity.

7.3.3 Outputs parameters generated by SimCCS

These inputs of capture costs at the power plant sources, transport costs along a particular pipeline route over Wyoming geography, sink costs for CO₂-EOR and sink costs for saline were fed into SimCCS and the solution to each of the three parts (source, transport, and storage) linked to the others. The interconnected and complex problem was then exported to CPLEX and solved. SimCCS output a Java visualization of the sources, sinks, and pipelines which connect them in the optimal solution. Additional outputs included a collection of shapefiles with the same information in GIS-compatible format, a results spreadsheet listing which sinks/source/pipelines were used at what capacities or utilizations, and a summary 2x4 table of total costs by year, total costs by unit of CO₂, and broken down by source, transport, and storage components. These shapefiles and spreadsheet data were post-processed in GIS applications.

7.3.4 Post-processing of SimCCS results

A major goal of the study is to estimate economic and jobs creation in specific localities in Wyoming. SimCCS is oriented towards creating the most efficient CO₂ network, but not geared specifically to provide inputs for this economic job-creation analysis. The authors therefore post processed the results to parse the physical components of the Wyoming network into a county-by-county basis.

The shapefiles produced from SimCCS include some relics reflecting how SimCCS solved the problem presented to it. The shapefiles created by SimCCS included georeferenced data on sources, transportation networks and sinks. The sources shapefile included attributes for ID number, latitude, longitude, CO₂ captured, maximum supply, PieWdge fractions, GensUsed, MaxGens, ActlCst, Ttlcst, Name and Cell#. The transportation networks shapefile included attributes for CapID, CapValue, flow, Cost, LengthKM, LengROW, LengCONS, and Variable. The sinks shapefile included attributes for ID number, latitude, longitude, amounts of CO₂Strd, MaxStrg, PieWdge fractions, WllsUsed, MxWlls, ActCst, TtlCst, Name and Cell#. These many and often confusing attributes were simplified as below.

All original shapefiles were projected to NAD 27 Wyoming Lambert Conformal Conic. These files were then modified to include new attributes for the transportation networks and sinks data. Attributes added to the networks shapefile included pipeline diameter and labels identifying power stations to sink network segments in kilometers. The network's shapefile was modified to merge multiple line segments of like diameters into one feature. Once the network features were merged, analysis produced the pipeline length in kilometers for each network segment. Attributes added to the sinks data included capex and O&M costs using information from the CCUS retrofit cost analysis. Unused sinks were deleted from the dataset.

Both the networks and sinks data were then divided to produce total kilometers of pipeline of each diameter within each county. The sinks data was also split by county summing capex and O&M costs values per county. Excel spreadsheets were created to show both the sinks by county listing the sum of capex and O&M costs. The networks were split up to produce length of pipeline segments within each county grouped by diameter.

After the initial analysis was submitted, it was decided to fine-tune the capex and O&M costs for sinks that would only utilize a fraction of the storage to proportionately reduce the cost of the storage. The adjusted capex and O&M costs totals were then analyzed and summed for total capex and total O&M costs by county.