AEMETIS

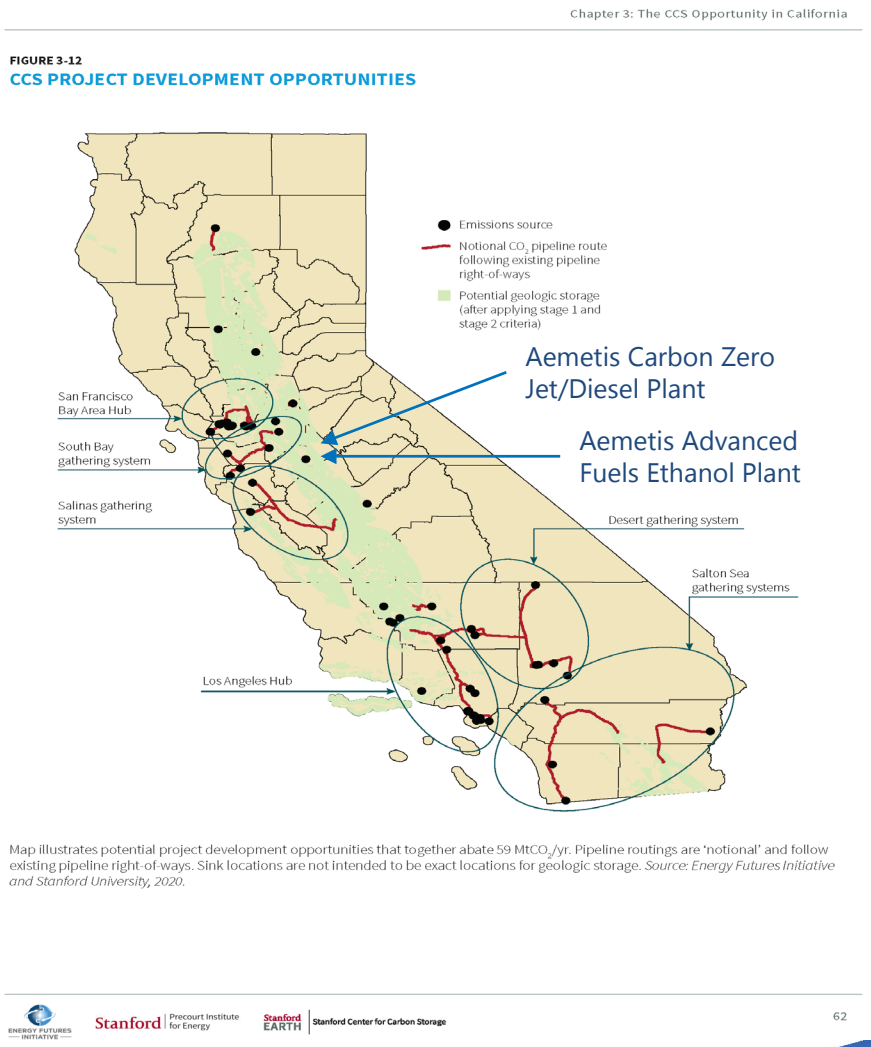
Aemetis Carbon Capture:
Carbon Capture & Sequestration (CSS) of CO2 for Renewable Fuels Plants in California

Aemetis Carbon Capture and Sequestration Projects in California

- Formerly an inland ocean now known as the Central Valley of California
  - Light green area shows shale geological storage containing saline water for CCS
  - Shale caprock layer at approximately 7,000 ft depth and basement layer below CO2 storage formation
- There are currently no operational CCS projects in the State of California
  - Few CCS projects in active development in California
- Aemetis plans to sequester 2 million metric tonnes of CO2 per year at two biofuel plant sites in CA:

  - 400,000 MT of CO2 per year expected from Aemetis biogas and biofuels plants

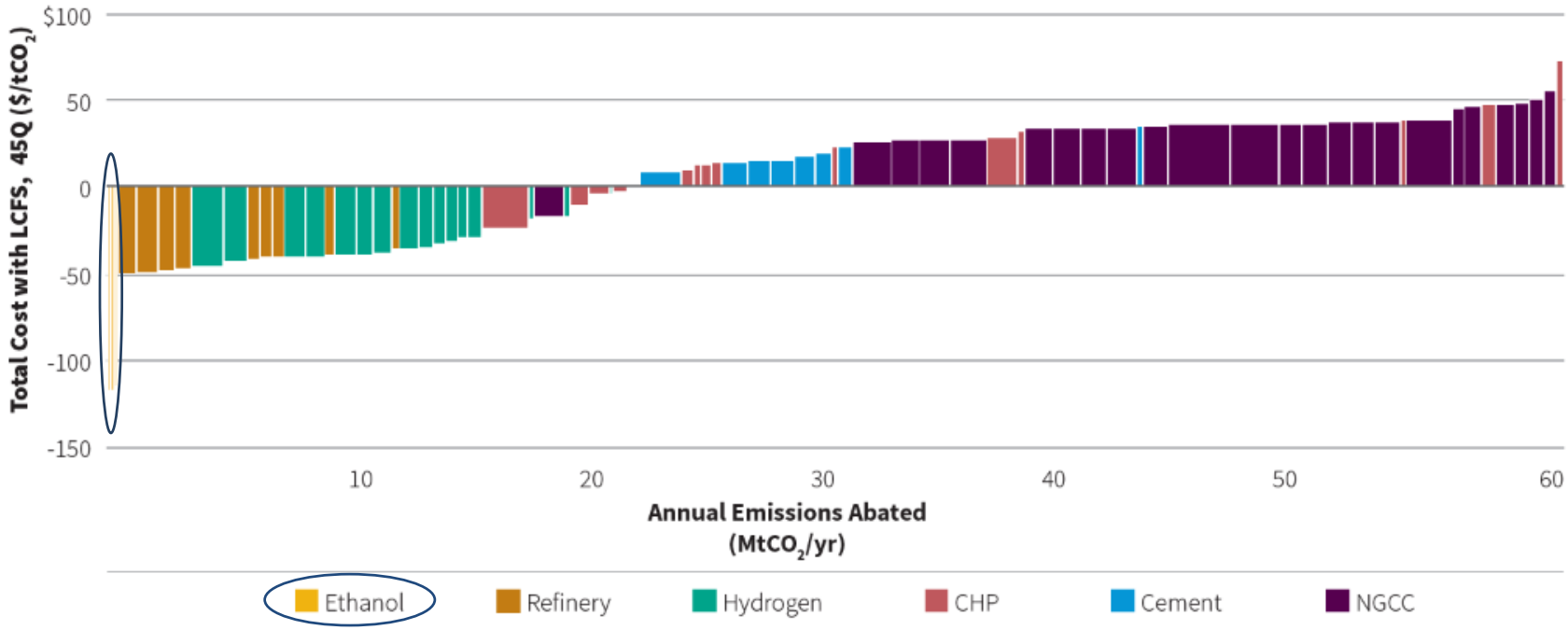
  - 1.6 million MT of CO2 per year expected using CO2 supplied by other renewable fuels plants and oil refineries
- Planned two million MT of CO2 sequestered each year could generate up to $500 million of annual revenues (assuming average of $200 LCFS and $50 IRS 45Q)



Ethanol Plants are Largest Reduction in Costs = Highest Value CCS Projects

FIGURE 3-14

MARGINAL ABATEMENT CURVE BY FACILITY



The 34 facilities on the left side of the graph that show negative costs can generate positive revenues. The opposite is true for the 42 facilities on the right side of the graph. Note that the crossover on this graph from negative to positive costs occurs at 21.5 $MtCO_2$/yr abated.
Source: Energy Futures Initiative and Stanford University, 2020.

k Abatement cost = capture cost ($/$tCO_2$) + storage cost ($/tCO_2) plus incentives (LCFS and 45Q credits where applicable, in $/$tCO_2$)

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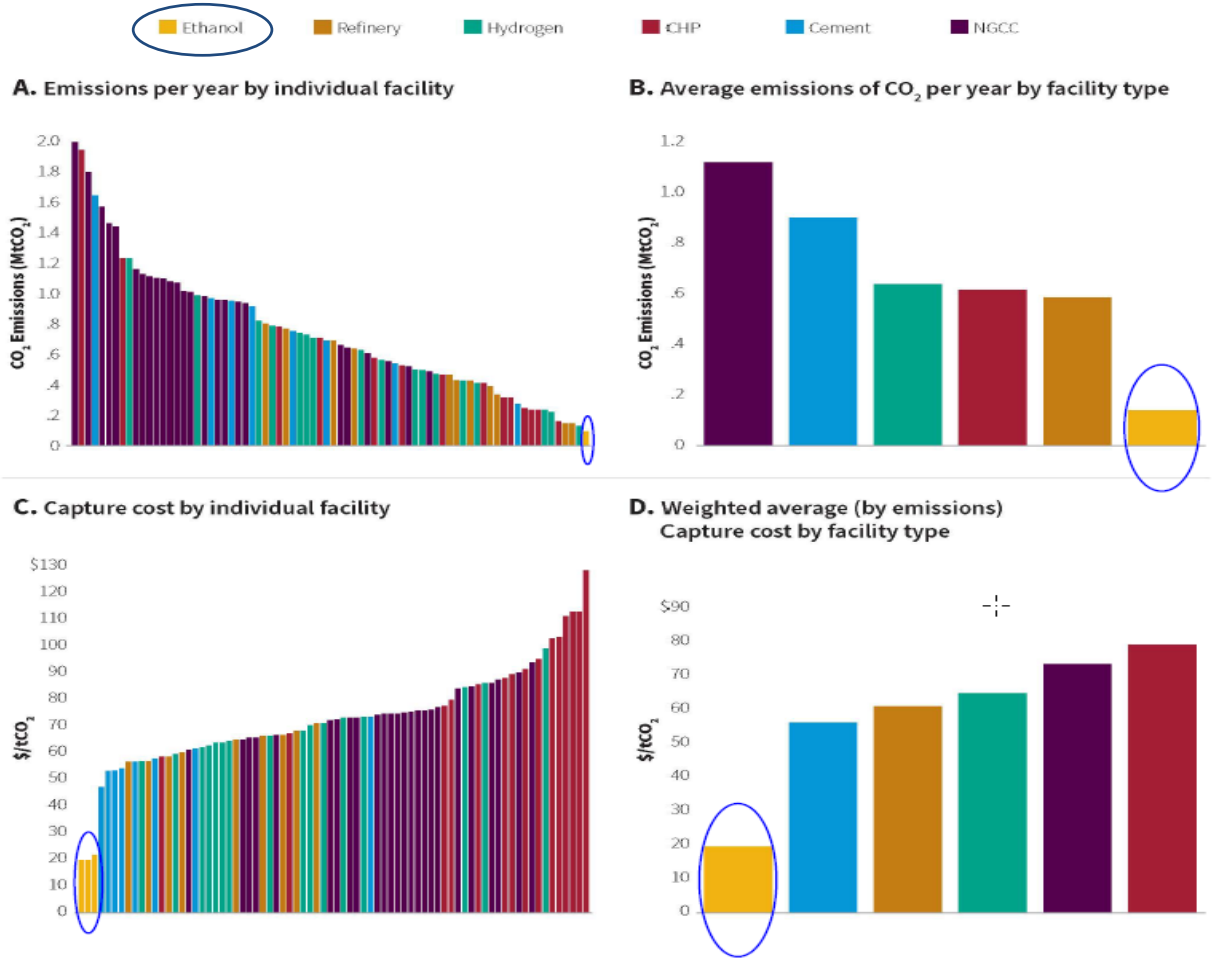
Emission Comparison and Capture Cost

FIGURE 3-13

COMPARISON OF EMISSIONS AND CAPTURE COST (BY FACILITY AND SUBSECTOR)



Emissions volumes and capture costs for the 76 candidate facilities analyzed in this study. *Source: Energy Futures Initiative and Stanford University, 2020.*

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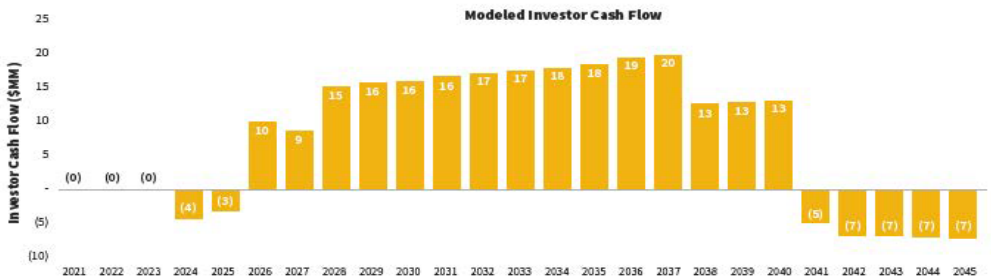
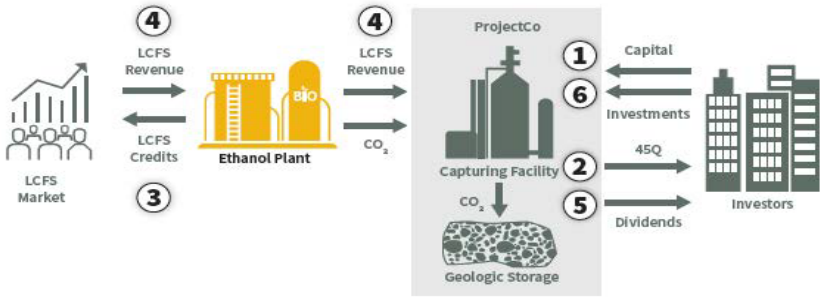
- Decreased Capture Cost with Pre-existing On Site CO2 Compression system
- Inverse relationship between plant emissions and storage capability
- Highest Emitters lack the geological positioning
- Aemetis has ability to receive CO2 by rail and inject into well

Sustainability:

FIGURE 3-15

GENERAL BUSINESS CONFIGURATION OF AN ETHANOL PRODUCTION FACILITY WITH CARBON CAPTURE AND CO-LOCATED STORAGE





1. Initial capital is made available to the ProjectCo from investors.
2. This includes tax equity investors who are essentially buying the 45Q tax credits.
3. Once operational, the capture facility receives CO_2 from the ethanol production facility and stores it within the permitted geologic storage location onsite and the ethanol facility generates LCFS credits from its capture efforts.
4. LCFS credits can be sold at market rates and receive LCFS revenues, a portion of which is contributed to the ProjectCo.
5. A portion of earnings resulting from the LCFS credit sale may eventually be transferred to investors in the form of a dividend (cash distribution).
6. Since tax equity investors are only obliged to contribute 50 percent of the cost of 45Q tax credits upfront, there will be ongoing investments through the lifecycle of the capture operation.

Positive cash flow (for duration of LCFS, assumed 15 years) indicates ethanol with CCS is an investable project. *Source: Energy Futures Initiative and Stanford University, 2020.*

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Aemetis Carbon Capture & Sequestration Project Leaders

ATSI: Carbon Sequestration Project Manager, Engineering and EPC

- For more than 40 years, ATSI has provided world-class Front-End Engineering Design (FEED/FEL), project management, EPC and commissioning services
- Major projects completed at more than 60 oil refineries, including commissioning of $10 billion oil refinery
- Completed 138 commercial projects in 21 different states

Baker Hughes: Underground Engineering and Well Drilling

- Leading natural gas and crude oil drilling company
- $20 billion market value
- Operates in 120+ countries
- CCUS Technology Solutions include:
    - Pre-FEED and FEED consultation and project design
    - Capture and purification
    - Injection Well design and construction for storage
    - Micro-seismic expertise

An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions

A joint study by:

ENERGY FUTURES INITIATIVE

Stanford | Precourt Institute for Energy

Stanford EARTH | Stanford Center for Carbon Storage

October 2020

About

ABOUT THE ENERGY FUTURES INITIATIVE

The Energy Futures Initiative (EFI) advances technically grounded solutions to the climate crisis through science-based analysis, thought leadership, and coalition-building. Under the leadership of Ernest J. Moniz, the 13th U.S. Secretary of Energy, EFI conducts rigorous research to accelerate the transition to a low-carbon economy through innovation in technology, policy, and business models. EFI maintains editorial independence from its public and private sponsors. EFI's reports are available for download at **www.energyfuturesinitiative.org**

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Through collaborations across campus, Stanford University's Precourt Institute for Energy fosters and supports the Stanford energy community. The institute and its programs fund research that has the potential to solve today's toughest energy challenges and help transform the world's energy systems. Stanford students can discover energy through the institute's experiential courses, internships, entrepreneurial activities, and a one-week orientation for incoming graduate students. The Precourt Institute works with industry leaders, entrepreneurs and policymakers for the broad deployment of solutions. It also engages a wide range of stakeholders at events like the Global Energy Forum. **www.energy.stanford.edu**

ABOUT STANFORD CENTER FOR CARBON STORAGE

The Stanford Center for Carbon Storage uses a multidisciplinary approach to conduct fundamental and applied research to address critical questions related to CO_2 storage in geologic formations. The center also conducts technoeconomic and policy/regulatory assessment of CCS projects. **www.sccs.stanford.edu**

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Boxes

List of Acronyms

Acronym	Meaning
°C	Degrees Celsius
°F	Degrees Fahrenheit
ADM	Archer-Daniels-Midland
AB	[California] Assembly Bill
ADF	Alternative Diesel Fuels
AIR	Association of Irritated Residents
API	American Petroleum Institute
ATC	Authority to Construct
BACT	Best Available Control Technology
BEA	U.S. Bureau of Economic Analysis
BECCS	Bioenergy with Carbon Capture and Storage
BEV	Battery Electric Vehicle
BLM	U.S. Bureau of Land Management
BTU	British Thermal Unit
CAA	Clean Air Act
CAISO	California Independent System Operator
CalEPA	California Environmental Protection Agency
CalGEM	California Geologic Energy Management Division
CAP	Criteria Air Pollutant
CARB	California Air Resources Board
CBA	Community Benefit Agreement
CCEJN	Central California Environmental Justice Network
CCS	Carbon Capture and Storage
CCST	California Council on Science and Technology
CCU	Carbon Capture and Utilization
CCUS	Carbon Capture, Utilization, and Storage
CDFW	California Department of Fish and Wildlife
CDR	Carbon Dioxide Removal
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CERCLA	Comprehensive Environmental Response Compensation, and Liability Act (Superfund)
CES	Clean Energy System
CFR	Code of Federal Regulations
CGS	California Geological Survey
CHP	Combined Heat and Power
CI	Carbon Intensity

Acronym	Meaning
CO_2	Carbon Dioxide
CO_2-EOR	Carbon Dioxide Enhanced Oil Recovery
COD	Commercial Online Date
CPUC	California Public Utilities Commission
CRC	California Resources Corporation
CRF	Capital Recovery Factor
CUP	Conditional Use Permit
CWA	Clean Water Act
DAC	Direct Air Capture
DACCS	Direct Air Capture with Carbon Storage
DDRDP	Dairy Digester Research and Development Program
DOE	U.S. Department of Energy
DOGGR	Department of Oil, Gas, and Geothermal Resources
DRECP	Desert Renewable Energy Conservation Plan
EA	Environmental Assessment
EFI	Energy Futures Initiative
eGRID	[EPA] Emissions and Generation Resource Integrated Database
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
FCCU	Fluid Catalytic Cracking Unit
FEED	Front-End Engineering Design
FERC	Federal Energy Regulatory Commission
FLIGHT	[EPA] Facility Level Information on GreenHouse gases Tool
GHG	Greenhouse Gas
GHGRP	[EPA] Greenhouse Gas Reporting Program
Gt	Gigaton
GW	Gigawatt
GWP	Global Warming Potential
H2A	[NREL] Hydrogen Analysis
HECA	Hydrogen Energy California
IBDP	Illinois Basin Decatur Project
ICCS	Illinois Industrial Carbon Capture and Storage

Acronym	Meaning
IEA	International Energy Agency
IEPR	Integrated Energy Policy Report
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
IRS	U.S. Internal Revenue Service
ITC	Investment Tax Credit
km	Kilometer
$ktCO_2$	Thousand Metric Tons of Carbon Dioxide
kW	Kilowatt
kWh	Kilowatt-hour
LAER	Lowest Achievable Emissions Rate
LCFS	Low Carbon Fuel Standard
LLNL	Lawrence Livermore National Laboratory
m	Meter
MMBTU	One Million British Thermal Units
MRR	Mandatory Greenhouse Gas Reporting Regulation
Mt	Million Metric Tons
$MtCO_2$	Million Metric Tons of Carbon Dioxide
$MtCO_2$/yr	Million Metric Tons of Carbon Dioxide per Year
$MtCO_2e$	Million Metric Tons of Carbon Dioxide equivalent
MW	Megawatt
MWh	Megawatt-hour
NATCARB	National Carbon Sequestration Database
NAAQS	National Ambient Air Quality Standard
ND	Negative Declaration
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NGCC-CCS	Natural Gas Combined Cycle with Carbon Capture and Storage
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NPC	National Petroleum Council
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value

Acronym	Meaning
NREL	National Renewable Energy Laboratory
NSR	New Source Review
O&M	Operations and maintenance
OOS	Out of state
PISC	Post-Injection Site Care
PM	Particulate Matter
PP&E	Property, Plant, and Equipment
PPM	Parts per Million
PSC	Public Safety Commission
PSD	Prevention of Significant Deterioration
PSI	Pound per Square Inch
PTC	Production Tax Credit
PTO	Permit To Operate
PV	Photovoltaic
R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
RD&D	Research, Development, and Demonstration
ROW	Right-of-way
RPS	Renewable Portfolio Standard
SB	[California] Senate Bill
SDWA	Safe Drinking Water Act
SIP	State Implementation Plan
SMR	Steam Methane Reforming
SOE	State Owned Enterprise
SWRCB	State Water Resources Control Board
SO_2	Sulfur Dioxide
tCO_2	Metric Ton of Carbon Dioxide
TWh	Terawatt-hours
UGS	Underground Gas Storage
U.S.	United States
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
USGS	United States Geological Survey
UIC	Underground Injection Control
WEA	Wyoming Energy Authority
WESTCARB	West Coast Regional Carbon Sequestration Partnership
ZEV	Zero-emission Vehicles

Summary for Policymakers

California is a leader in addressing climate change. With some of the strongest decarbonization targets in the country—40 percent emission reductions by 2030, carbon neutrality by 2045, and net-negative emissions thereafter—California continues to pursue innovative policies to achieve ambitious emissions reductions.

At the same time, the impacts of climate change are becoming increasingly clear and common, and have had devastating impacts on the state: wildfires that have burned over four million acres; droughts; and heatwaves, like those that precipitated rolling electricity blackouts across California in August 2020. Average temperatures across the state are increasing, with Southern California warming by about 3 degrees Fahrenheit (°F) in the last century.[1] In comparison, California warmed approximately 1.5°F over the course of the previous century.[2]

Successful policy pathways for achieving California's ambitious emission reduction targets are critical. Additional and accelerated actions are needed to ensure that the state successfully transitions to a carbon-neutral economy both economically and equitably. With the world's fifth-largest economy, California's success in meeting its statewide targets has significant implications for the global climate.

California has a strong economic base, skilled workforce, and robust innovation capacity at its laboratories, universities, and technology companies. California must rely on these strengths and foundations while building powerful coalitions of policymakers, citizens, environmental and social justice advocates, industry leaders, and scientists to achieve its climate goals. California's leadership and citizenry are focused on the core objective—a net-zero greenhouse gas (GHG) emissions economy—using the full range of options to help meet this difficult but critical goal. California cannot afford to limit its flexibility by eliminating technology options or pursuing unfocused or suboptimal policies that may hinder, rather than accelerate, decarbonization.

This study, *An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions*, provides policymakers with options for near-term actions to deploy carbon capture and storage (CCS), a clean technology pathway well suited for rapidly reducing emissions from economically vital sectors in California that have few other options to decarbonize. This analysis builds on previous work, including the Energy Futures Initiative's (EFI) 2019 report *Optionality, Flexibility, and Innovation: Pathways for Deep Decarbonization in California,* which concluded that the targeted use of CCS could be one of the largest single contributors to California's decarbonization by 2030, and contribute to deep decarbonization by midcentury as well.[3]

CCS, like all other emission reduction technologies, is not a "silver bullet" technology for decarbonization. Carbon capture paired with permanent geologic storage (e.g. deep saline reservoir) offers a viable and important option for reducing emissions from the industrial and electricity sectors that are key contributors to California's economy and the reliability of its grid. Several industries—chemicals, transportation fuels, cement, plastics, and rubber products—rely on facilities that are large sources of emissions. With CCS, these facilities and sectors could be rapidly decarbonized and continue to make major contributions to the state's economy while helping it meet its near-term and midcentury climate targets.

Forty-three percent of California's in-state electricity generation in 2019 was natural gas-fired.[4] In addition to being the largest fuel source for in-state power generation, natural gas remains a prominent source of firm generation for California. In the power sector, CCS can be paired with natural gas combined cycle (NGCC) power plants to create a "clean firm" resource, which multiple studies identify as critical for maintaining grid reliability and managing energy system costs as California continues to build out its renewable resources. An analysis of California's pathways for achieving its Senate Bill (SB) 100 goals indicated that California will need approximately 30 gigawatts (GW) of clean firm generation resources[a,5] to cost-effectively decarbonize its grid.[6] The value of clean firm generation should not be underestimated through the clean energy transition.

Technoeconomic analysis done for this study identified 76 existing electricity generation and industrial facilities in California as candidates for CCS, representing close to 15 percent of the state's current GHG emissions. To put this in perspective, in 2017, California's buildings sector was responsible for 10 percent of its emissions and its power sector emitted 15 percent of the total.[7]

CCS is a strong complement to other decarbonization strategies. For California's cement industry, CCS is considered one of the most cost-effective carbon reduction options and supports other strategies like increased energy efficiency, clinker substitution, and fuel switching.[8]

CO_2 storage is a critical enabler of prominent carbon dioxide removal (CDR) pathways, including: direct air capture (DAC) and conversion of waste biomass to zero- or negative-carbon transportation fuels and electricity.

As of September 2020, there were five announced CCS projects in varying stages of planning and development in California.[b] These projects will provide valuable lessons learned for future project developers, policymakers, and regulators. The design of these early projects provides insight into the opportunities and challenges of pursuing CCS in California today. For example, the two projects closest to becoming operational leverage existing infrastructure and brownfield sites to manage total project costs, are designed to generate revenues in addition to those provided by policy incentives, and are co-located with CO_2 storage resources, eliminating the need to permit and build CO_2 pipeline infrastructure.

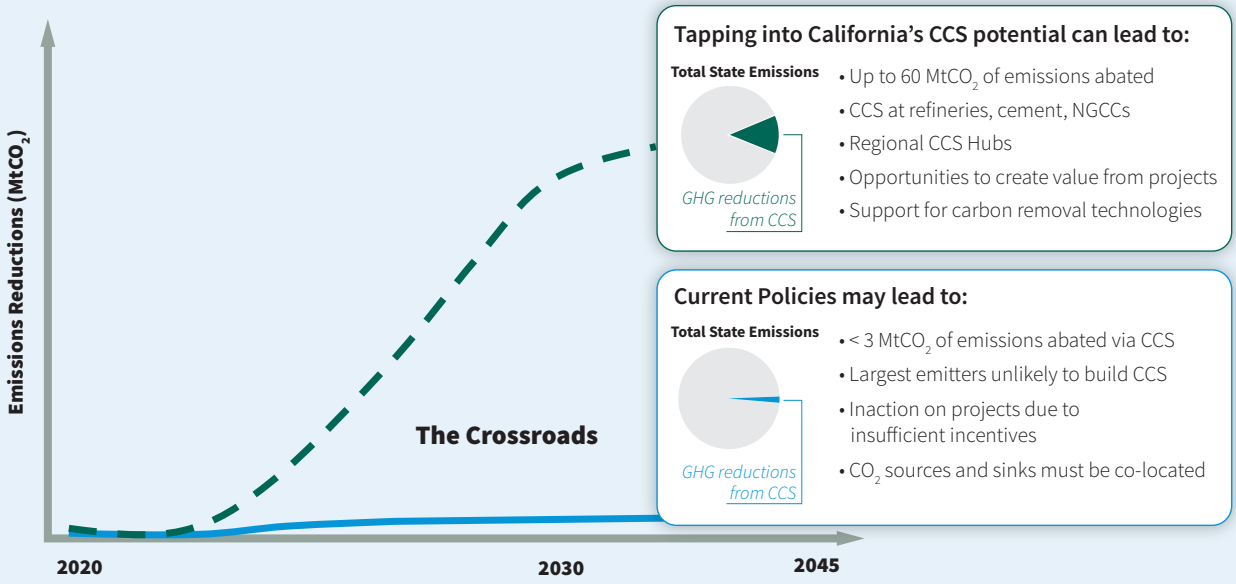
Today, California is at a crossroads in CCS development (Figure S-1). Despite a strong foundation of climate policy support, sizeable technical potential to rapidly decarbonize, and natural resources that could enable the state to become a leader in CCS, it has no CCS projects that are operational. If CCS is to play a meaningful role in meeting the state's 2030 emission reduction targets and 2045 carbon neutrality ambitions, California policymakers should consider additional and immediate actions to promote targeted deployment of CCS today.

a The U.S. EIA defines firm power as "power or power-producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions." Clean firm generation includes firm power resources that are low- or zero-emissions, including nuclear, geothermal, biomass, hydro, NGCC-CCS, hydrogen and other carbon free fuels using net-zero processes.

b This includes Clean Energy Systems (CES) biomass to hydrogen with permanent geologic storage; California Resources Corporation (CRC) NGCC capture used for EOR; DTE Energy's transport and storage hub concept; Chevron's NGCC capture pilot, and a carbon capture pilot on the Los Medanos NGCC owned by Calpine Corporation. Note: only the CRC project is included in the Global CCS Institute CO2RE Database utilized in Chapter 1 to profile Global and US CCS development.

FIGURE S-1

CALIFORNIA IS AT A CROSSROADS FOR CCS TO CONTRIBUTE TO GREENHOUSE GAS REDUCTION BY MIDCENTURY



California is at a crossroads for CCS. In the current policy environment, there will likely be few projects with very limited emission reductions potential. With affirmative policy support, CCS could play a major role in enabling the state to meet its climate goals by midcentury. *Source: Energy Futures Initiative and Stanford University, 2020.*

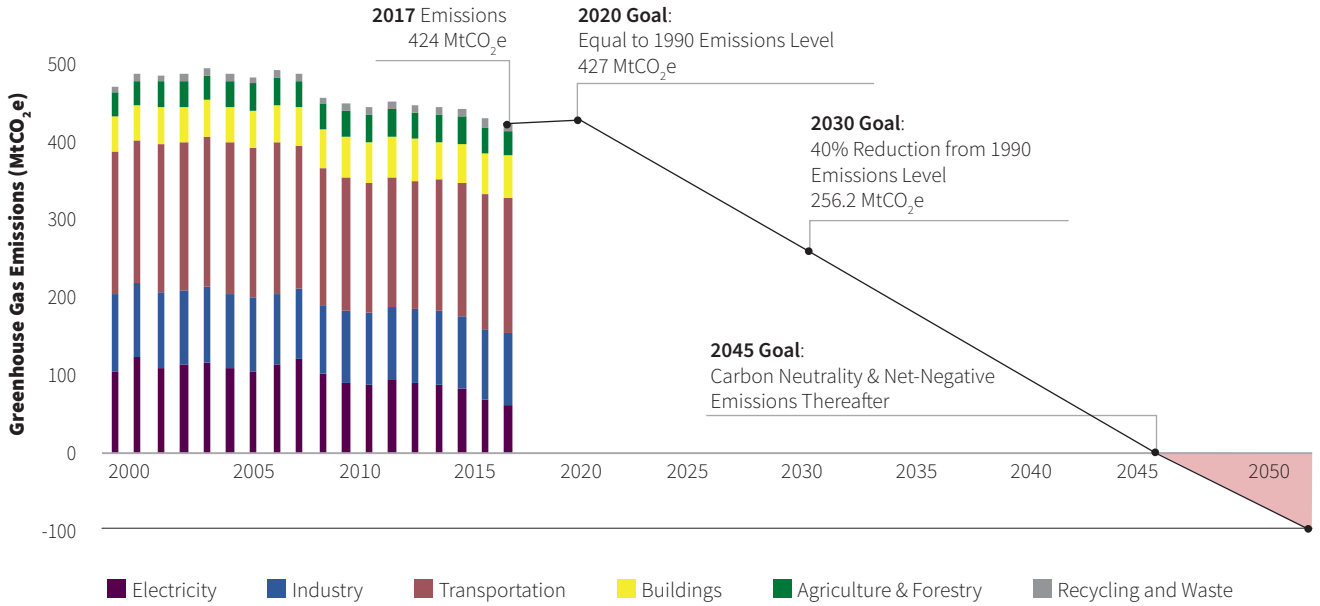
MAJOR ENABLERS OF CCS IN CALIFORNIA TODAY

There are strong drivers for CCS in California today. These include: the urgent need for early emission reductions to achieve 2030 targets and economywide carbon neutrality by midcentury; policy support from the Low Carbon Fuel Standard (LCFS) CCS Protocol; the commercial readiness of CCS; CCS as one of few options to reduce emissions from industry, one of the most difficult sectors to decarbonize; and the opportunities provided by CCS to transition the existing traditional energy workforce to clean energy jobs.

California has a strong foundation for supporting CCS projects. California's industrial and electricity sectors have sizeable technical potential to incorporate CCS technologies—this study identified 76 facilities that are suitable for carbon capture, with the capacity to remove 59 million metric tons of carbon dioxide ($MtCO_2$) annually by 2030. California's policy goals to reach economywide carbon neutrality by 2045 and net-negative emissions thereafter (Figure S-2) will likely require CCS: many studies including the Intergovernmental Panel on Climate Change (IPCC) *Special Report on Global Warming of 1.5 °C,*[9] and the International Energy Agency (IEA) *World Energy Outlook 2019,*[10] find that reaching net negative emissions will require a significant amount of carbon removal.

FIGURE S-2

CALIFORNIA'S HISTORIC EMISSIONS & FUTURE EMISSION REDUCTION TARGETS



California has already met its 2020 emission reduction target; however, it has increasingly stringent goals in 2030 and by midcentury that require additional technologies, policies, and decarbonization solutions. *Source: Energy Futures Initiative and Stanford University, 2020.*

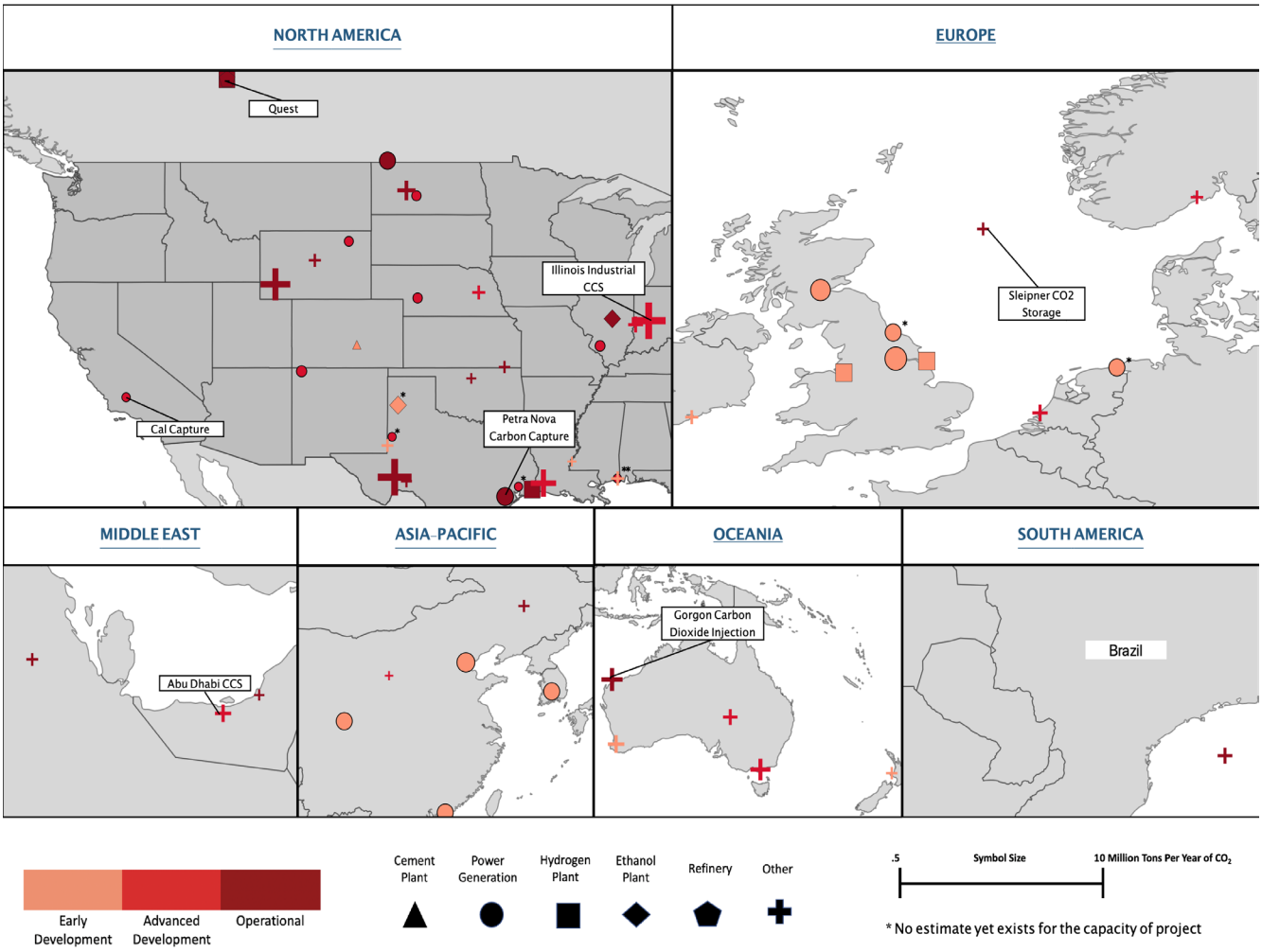
California's economy would see rapid near-term emission reduction benefits from CCS. A major motivation for deploying CCS in California is that it can be applied to multiple sectors of the economy, including those with large workforces and few decarbonization options: petroleum refining; hydrogen production; combined heat and power (CHP); cement production; and ethanol production. These industries are difficult to decarbonize without CCS due to a combination of factors, including high temperature requirements that cannot be practically met with electrification, and high levels of systems integration at many facilities, which make major changes highly disruptive to facility operations. Also, emissions from cement production, for example, are 60 percent from the process itself rather than from fuel combustion, which makes it especially difficult to decarbonize.[11] CCS, a post-combustion bolt-on option, can address these emissions sources with relatively little disruption in normal functions (assuming sufficient space is available at the site).

CCS activities would provide jobs for Californians with skillsets that may become obsolete in the clean energy transition. There are skillsets in the traditional energy sector, such as geologists, petroleum engineers, chemical engineers, process technicians, pipeline workers, and other related construction skills that could be re-deployed to support CCS. In 2019, there were 412,000 traditional energy jobs in California.[12] As conventional energy sector jobs decline, these workers could transition to jobs in the CCS industry that require similar knowledge and skills. Importantly, supporting a CCS and hydrogen production industry that allows for the transfer of skills and experience of today's workforce is aligned with the state's commitment to an equitable and just clean energy transition as CCS creates opportunities for new industries and jobs.

CCS is a commercially ready, clean energy technology that is growing globally. Globally, as of September 2020, there were 61 large-scale CCS facilities that were either operational, in advanced development (i.e. under construction or in an advanced planning stage), or in early development (i.e. early planning) (Figure S-3). California could become a global leader in CCS development and deployment to achieve its climate goals as it has with other clean energy technologies, but to do so, it needs to act quickly and comprehensively.

FIGURE S-3

GLOBAL CCS PROJECTS BY REGION, STATUS, AND SOURCE TYPE



Globally, CCS projects have operated since the 1990s with 21 large-scale projects in operation as of September 2020, and 40 in various stages of development. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Global CCS Institute, 2020.*

OPPORTUNITIES TO RAPIDLY DECARBONIZE AND CREATE NEW CLEAN INDUSTRIES AND JOBS

California has opportunities to advance its decarbonization and economic goals by leveraging CCS due to its sizeable geologic storage resources; the suitability of its emissions sources for carbon capture; its need for clean firm electricity generation as the renewable energy profile grows; the need for decarbonized transportation fuels, such as hydrogen; and its experience advancing strong climate policies and innovative industries.

California's geology makes it well suited for safe, permanent CO_2 storage. As noted, multiple studies[13,14] have concluded that California has an enormous capacity and high-quality resources for storing CO_2.[15] One study done by the WESTCARB Regional CCS partnership, an organization led by the California Energy Commission (CEC) and the U.S. Department of Energy (DOE), estimated the CO_2 storage capacity of saline formations in the ten largest basins in California ranged from 150 to 500 gigatons (Gt), depending on assumptions about the fraction of the formations used and the fraction of the pore volume filled

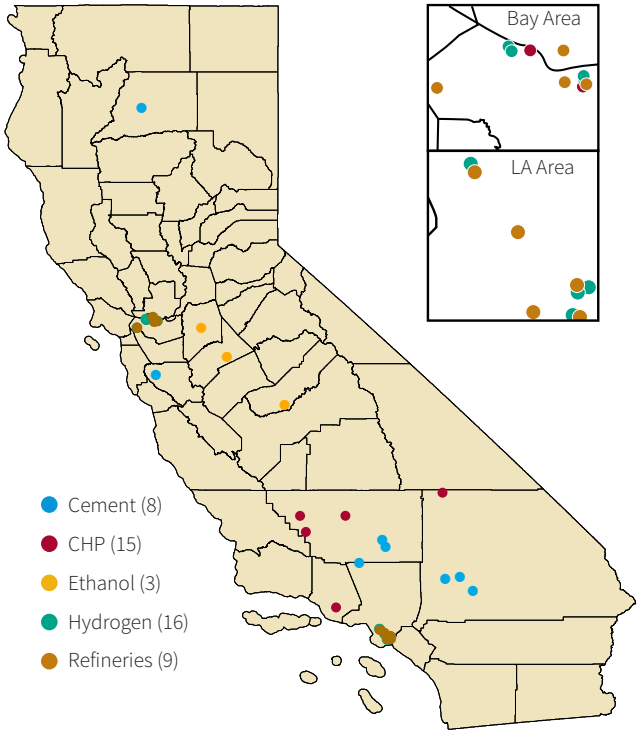
with supercritical-phase CO_2. Several factors in key regions make California particularly well suited for CO_2 storage. Layers of thick alternating sands and shales and broad structural closures, the same elements that are useful for trapping large quantities of oil and gas, are present in both the Central Valley and Ventura Basins. The state has the potential to store 60 $MtCO_2$/yr—the equivalent of total electricity sector emissions in 2017—for 1,000 years.

There are important policy incentives that make CCS attractive. California established the LCFS in 2009 with the goal of reducing GHG emissions from its transportation sector and increasing the range of availability of transportation fuels in California to reduce petroleum dependency and improve air quality.[16] In 2018, the California Air Resources Board (CARB) adopted a CCS Protocol, which enables new and existing CCS projects to generate LCFS credits and participate in the credit market.[17] LCFS credits have traded at all-time highs of nearly \$200/tCO_2, providing a significant financial incentive for eligible CCS projects. The federal 45Q tax credit also provides incentives for dedicated geological CO_2 storage, CO_2 stored through enhanced oil recovery (EOR), or CO_2 utilization. Both LCFS credits and 45Q credits can be used by project developers, creating significant financial incentives; however, the 45Q credit requires that projects commence construction by January 1, 2024,[18] necessitating immediate action by project developers.

CCS offers a robust pathway for deeply decarbonizing several industrial subsectors in California. This analysis identified 51 industrial emitters in California as candidates for CCS, including 16 hydrogen facilities, 15 CHPs, nine petroleum refineries, eight cement plants, and three ethanol production facilities (Figure S-4). These facilities emitted nearly 36 $MtCO_2$ in 2018, of which approximately 27 $MtCO_2$ could be abated by CCS. The three ethanol plants are situated above suitable geologic storage in the Central Valley. The hydrogen and refining facilities benefit from eligibility for both LCFS and 45Q tax credits, though their location in the Los Angeles and San Francisco Bay metro areas necessitate new CO_2 transportation infrastructure to access suitable geologic storage. Some of the CHP facilities are associated with refining operations, making them suitable for CCS "hubs" in which capture operations located close together can share CO_2 transport and storage infrastructure, greatly reducing costs and infrastructure buildout. Finally, the cement plants have relatively low capture costs, while being a significant contributor to the state's economy; however, cement is not eligible for LCFS credits and will require CO_2 transport, making it more challenging from a project development perspective.

FIGURE S-4

CO_2 CAPTURE OPPORTUNITIES IN THE INDUSTRIAL SECTOR



This analysis identified 51 industrial facilities across five subsectors that are candidates for CCS retrofit in California. Note: Upper inset map is the San Francisco Bay Area. Lower inset map is the Los Angeles area. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from U.S. EPA, 2020.*

CCS on NGCC power plants provides a cost-competitive pathway for providing clean, firm—and essential—power. California's electricity sector currently has one of the lowest emission intensities in the U.S. because of its lack of coal-fired generation, high penetration of renewables, and relatively newer and more efficient natural gas generation fleet.[19] As the grid continues to decarbonize, especially through the deployment of intermittent renewable resources, the value of clean firm resources will grow. In 2017, California had 90 days with

little to no wind generation, for as many as 10 days in a row; battery storage is typically four hours duration. There is also significant seasonal variation. Solar production was 1.5 terawatt-hours (TWh) in January 2017 but 3.2 TWh in June.[20] California currently has about six GW of clean firm resources, including nuclear, geothermal, and biomass power, which in 2018 were responsible for approximately 16 percent of total system generation. This analysis found that a 2030 scenario with NGCC-CCS saved $750 million per year in total electricity system costs compared to a system without CCS that relied heavily on renewables and battery storage. A separate study estimates that by 2045, California will need approximately 30 GW of clean firm resources to ensure sufficient supply all year long.[21] Another recent study of California's electric grid under deep decarbonization scenarios found: "Some form of firm generation capacity is needed to ensure reliable electric load service on a deeply decarbonized electricity system."[22]

Ten candidate facilities for CCS are co-located with high-quality CO_2 storage resources. This study identified three ethanol plants, two CHPs, and five NGCCs that are located directly above potential CO_2 storage reservoirs. CCS for these facilities could reduce emissions 5.6 $MtCO_2$/yr. These facilities should be considered for initial demonstration projects because they do not require new CO_2 transportation infrastructure, which can add significant cost, potentially require engagement of many landowners, and involve lengthy and complex permitting processes. As noted, the two projects closest to operation in California today both have an emissions source co-located with CO_2 storage. This study also identified an additional 4.1 $MtCO_2$/yr from two CHPs and three NGCCs that are close to suitable CO_2 storage, and would require minimal infrastructure development.

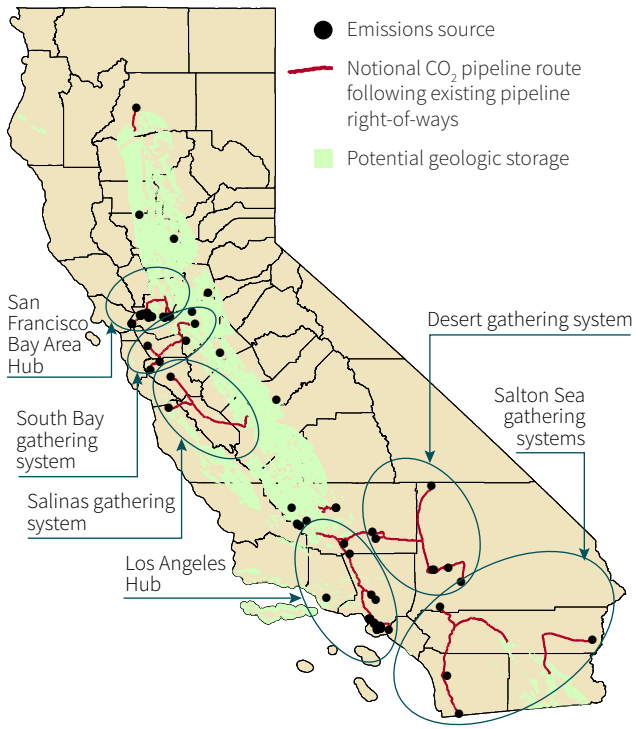
Deployment of CCS infrastructure can enable the emergence of new, potentially multi-billion-dollar clean energy industries, creating new jobs and value for the state's economy. Building out a CCS infrastructure can support the ultimate development of clean hydrogen, which has significant economic potential. Many studies show significant promise for using hydrogen to deeply decarbonize industry, heavy-duty transportation, electric power, and home energy needs. The least expensive method for producing clean hydrogen today uses a process called steam methane reforming with carbon capture; using this method could enable the development of a broader hydrogen infrastructure, while investing in ways to lower the costs of "green hydrogen" from electrolysis, which is currently 4-5 times more expensive than so-called "blue hydrogen" produced using natural gas. One study estimated that, by 2050, the hydrogen economy in the United States could generate $750 billion per year in revenue and support a cumulative 3.4 million jobs.[23]

Another emerging pathway to carbon neutrality is DAC, which removes CO_2 directly from the atmosphere and may be essential for achieving net-zero goals.[24] Similar to clean hydrogen, DAC relies on carbon storage or utilization after it is captured.[25] DAC has a significant carbon removal potential and can be co-located with suitable storage or utilization sites, eliminating the need for long-distance CO_2 transport.

California is well suited to develop carbon capture hubs where there is a high concentration of CO_2-emitting facilities and access to permanent storage capacity via shared pipeline. Hubs offer "economy of effort," where the economics of project design studies, permitting, and construction would be more favorable due to co-location of emissions sources. Pursuing CCS hubs can also ensure a targeted development of a CCS industry compared to many potential point-to-point projects. This study identified potential CCS hubs aimed at drastically reducing pollution from the large source clusters in the Los Angeles and San Francisco Bay areas, which could result in emissions reductions of 25 $MtCO_2$/yr and 14 $MtCO_2$/yr, respectively (Figure S-5). Project costs could also be managed using centralized storage facilities that accommodate multiple sources of CO_2.

FIGURE S-5

CCS PROJECT DEVELOPMENT OPPORTUNITIES



Map illustrates potential project development opportunities that together abate 59 $MtCO_2$/yr. Pipeline routings are 'notional' and follow existing pipeline right-of-ways. Sink locations are not intended to be exact locations for geologic storage. *Source: Energy Futures Initiative and Stanford University, 2020.*

CHALLENGES FOR DEVELOPING A ROBUST CCS INDUSTRY IN CALIFORNIA

Informed by interviews with project developers, financiers, and industry stakeholders, this analysis identified existing barriers to CCS project development, including: ambiguous state support for CCS, complex and untested regulatory process, revenue and cost uncertainty, and lack of public awareness and support.

Despite the strong project economics provided by federal and state incentives and California's foundational resources, there are, as noted, currently no operational CCS projects in the state. There are, however, a small number of CCS projects in active development. Their developers plan to take advantage of the 45Q tax credit and the state's LCFS program with supplemental revenues coming from selling electricity or fuels, and they are also taking advantage of existing infrastructure and close proximity to quality CO_2 storage resources. These first movers are very valuable, but many more projects are needed to maximize the potential CCS holds for helping to meet the state's ambitious climate targets. If CCS is to play a meaningful role in meeting California's 2030 and 2045 emissions reduction targets, California needs to address the regulatory and financial barriers to CCS deployment to enable the state's largest emitters to rapidly develop CCS projects.

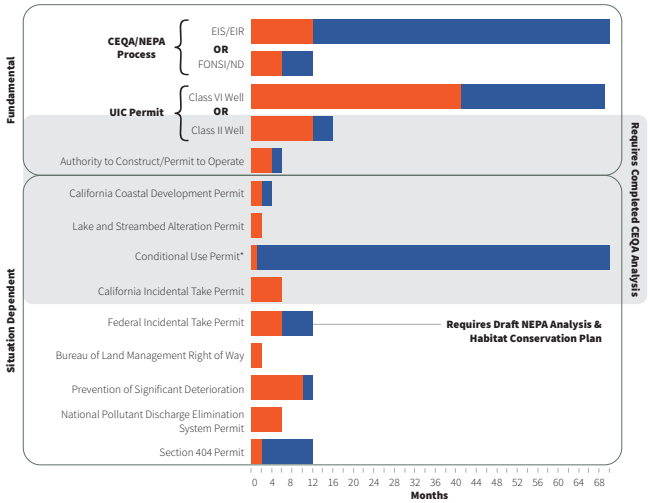
California policies and policy studies paint an ambiguous picture of the future role of CCS for some project developers and investors. California has issued major policy studies that describe the potential value of CCS to the state's decarbonization. In 2011, California Council on Science and Technology (CCST) issued its *"California's Energy Future—The View to 2050 Summary Report"* that found CCS to be an important strategy for achieving the state's GHG reduction targets under several scenarios.[26] In 2017, CARB's *"California's 2017 Climate Change Scoping Plan"* found that CCS "offers a potential new, long-term path for reducing GHGs for large stationary sources."[27] In 2018, CARB issued the CCS Protocol, making it possible for CCS projects to receive credits under the

LCFS program.[28] CCS is, however, ineligible for Cap-and-Trade and is not currently included in the analysis for SB100, the California Public Utility Commission's (CPUC) Integrated Resource Plan, and CEC's Integrated Energy Planning Report.

CCS projects have unique and relatively new planning and permitting requirements compared to other energy infrastructures in California. Permitting CCS projects can be a significant undertaking, as agencies involved may not be familiar with CCS, developers may not be familiar with the myriad of permits required for a complex CCS project, and the timelines for certain key permitting steps—namely the California Environmental Quality Act (CEQA) review and the Underground Injection Control (UIC) program Class VI application—are uncertain and potentially lengthy (Figure S-6). Because CCS projects involve at least two processes (capture and storage), and sometimes transport as well, they can cross multiple regulatory jurisdictions. This makes permitting very complex to navigate, especially considering the relative newness of the CCS technologies. For example, at least three different California agencies may be involved in CCS at an industrial facility at the outset of a project: the local air district for Clean Air Act permitting (Authority to Construct/Permit to Operate), EPA Region 9 or the California Geologic Energy Management Division (CalGEM) for UIC injection well permitting, and another agency (typically a local agency) to serve as the "lead agency" for CEQA.

FIGURE S-6

ESTIMATED CCS PROJECT PERMITTING TIMELINES



**Conditional Use Permits (CUPs) must be in accordance with the city or county's general plan (i.e. meet the development objectives) to be approved. General plans are not updated often, so this should be taken into careful consideration by a developer.*[29]

This figure illustrates timelines of permitting processes that may be required to develop a CCS project in California. The timelines are notional estimates based on federal and state guidelines, project case studies, and agency reports. The orange bars are a minimum estimated permitting duration from application to permit issuance, while the blue bars indicate how long the process could potentially take. Blue bars that extend to the end of the graph represent processes that could have an indefinite timeframe. Permits shaded in grey require a completed CEQA (either an ND or EIR) to commence. *Source: Energy Futures Initiative and Stanford* University, 2020.

CCS projects rely heavily on policy incentives (some relatively new), creating revenue and cost uncertainty. Absent public policy support mechanisms, there are few incentives to capture CO_2 emitted from facilities. As noted, two policies—the LCFS and 45Q—provide needed cash flows for eligible projects to justify the capital and operational expenses required to design, build, and operate CCS facilities. However, there are challenges related to the duration and value of these incentives, that can limit developer and investor interest in CCS. There are also cost-related uncertainties that add pressure to the overall project economics. In addition to the construction and operating costs, there are issues related to the costs of financial responsibility associated with UIC Class VI wells, the time needed to acquire necessary permitting, and establishing the feasibility of projects (e.g. obtaining the necessary permits and social license). Taken together, these revenue and cost challenges have contributed to a general lack of investor capital to fund CCS projects, especially those sources that contribute most significantly to CO_2 emissions that currently have access to fewer financial incentives than some of the smaller sources.

Public understanding and support of CCS vary, potentially impacting developer and investor interest. CCS technologies and their value are unknown to many in the public, and among those who are familiar with the technology, public attitudes are highly variable.[30] Public acceptance is a cross-cutting issue, potentially affecting each category of challenges to project development. Analysis suggests that individuals are influenced by relationships with their communities; better community relationships translate into greater individual support for CCS.[31] It is important for California as it considers the role CCS will play in its zero-carbon future, to prioritize outreach and education to all Californians, but especially those in affected communities. It is critical that these communities and stakeholders participate in decision-making to ensure CCS will promote a just transition to a zero-carbon California.

ACTION PLAN FOR POLICYMAKERS TO UNLOCK CALIFORNIA'S CCS POTENTIAL

A combination of policy actions supported by broad coalitions can maximize the value of CCS for meeting the state's economywide decarbonization goals, motivating the private sector to decarbonize, enabling economic and reliability benefits from existing industries and power generation, and unlocking new clean energy industries and jobs.

CCS is a critical decarbonization pathway for helping California meet its 2045 carbon neutrality goal, while also supporting related goals that are fundamental enablers of the clean energy transition and key to building the necessary coalitions. The goals are:

1) Maximizing options for meeting 2030 and 2045 GHG targets to reduce overall abatement costs, improve the likelihood of achieving the targets, and foster innovation.

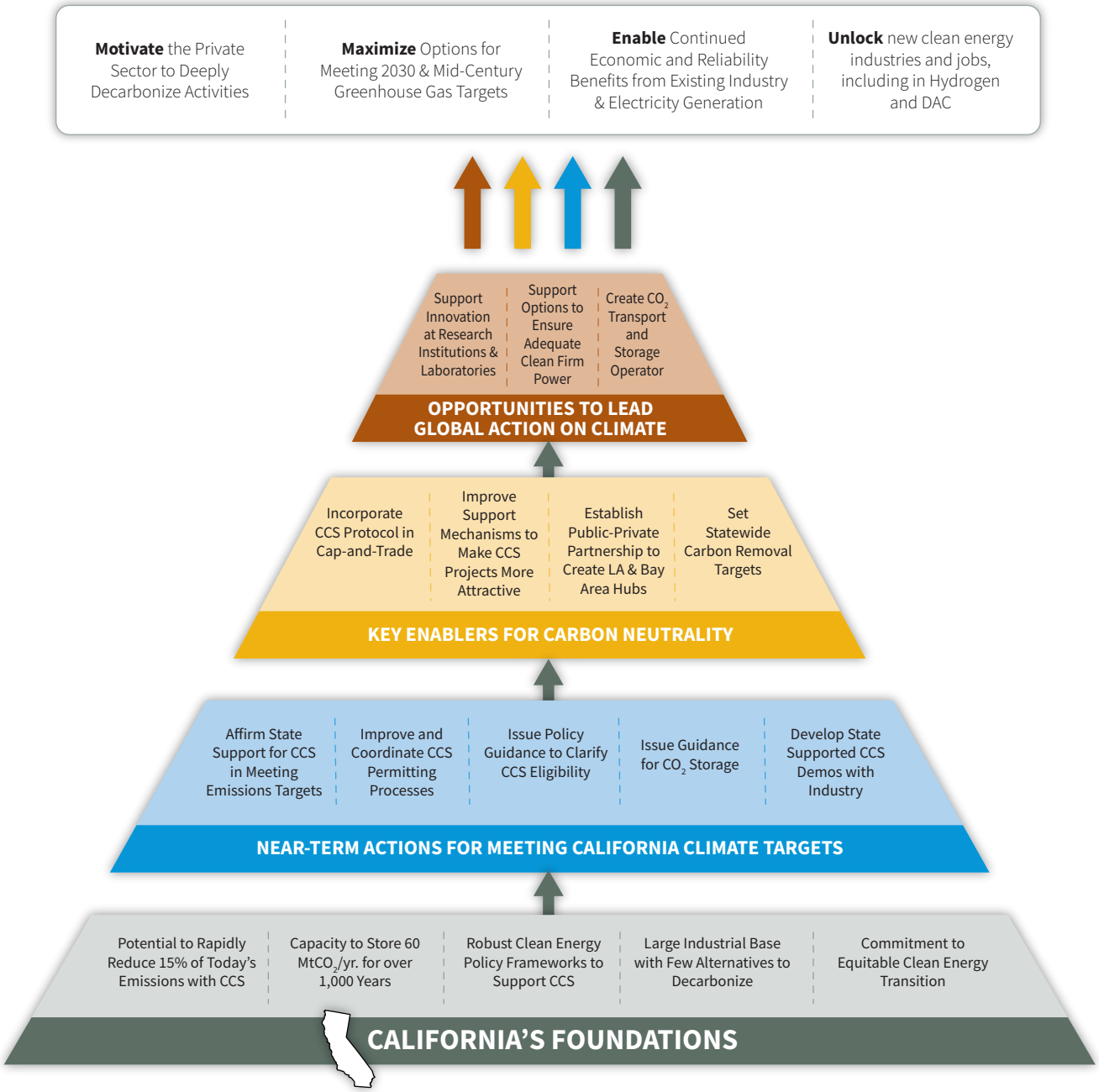
2) Motivating the private sector to deeply decarbonize its activities and products.

3) Enabling continued economic and reliability benefits from existing industries and power generation.

4) Unlocking new, potentially multi-billion-dollar, clean energy industries—such as hydrogen, CO_2 utilization, DAC, and fuels from biomass waste—creating new jobs in the process. Figure S-7 shows more detail.

FIGURE S-7

A POLICY ACTION PLAN FOR CCS IN CALIFORNIA TO MEET THE HIGH-LEVEL GOALS



The analysis in this report informed the establishment of high-level goals for CCS in California at the top of the figure. California has a strong foundation for CCS development. Key drivers—near-term actions for meeting climate targets, enablers of carbon neutrality, and opportunities to lead global action—inform and increase CCS project development in specific areas of recommended actions.
Source: Energy Futures Initiative and Stanford University, 2020.

California should take near-term actions to leverage its CCS potential for meeting its climate targets of 40 percent emissions reduction by 2030 and to pave the way for carbon neutrality by 2045.

- ***Affirm state support for CCS in meeting emissions targets.*** CCS projects can have immediate and long-lasting environmental, economic, and jobs benefits to nearby communities. The state should issue policy guidance, such as an executive order, affirming the conclusions of CARB and CEC about the need for and value of CCS. Policy guidance should also direct all relevant state agencies to align their respective CCS regulatory activities with the high-level goals discussed above. This would provide policy certainty and help align perspectives across the stakeholder landscape. Project developers, local governments, and community representatives could work collaboratively to provide input that would maximize the benefits of CCS projects and articulate these benefits to the public.
- ***Improve and coordinate CCS permitting processes.*** Building new infrastructure to support the emerging CCS industry requires strong financial, policy, and regulatory support. The regulatory environment for CCS in California is relatively untested, which makes it difficult to acquire the permits and financing necessary to move projects forward. Improved coordination could be achieved by California's Executive Branch assigning a lead coordinating agency for CCS permitting activities that could work with other agencies with existing permitting authorities to develop clear permit review timelines, establish permit submission sequencing guidelines, and support transparent review processes. California could also establish a multiagency working group to identify overlapping or redundant processes and increase coordination for permit applications and reviews.
- ***Issue policy guidance to clarify CCS eligibility.*** As new clean energy technologies emerge, there are often questions regarding their compatibility with existing policies and regulations. California could incorporate CCS into its integrated resource plan (IRP) process to rigorously assess the potential economic and emissions reduction opportunities afforded by NGCCs with CCS. California could also make CCS an eligible resource under the SB100 goal of 100 percent of retail electricity sales from renewable and zero-carbon resources by 2045. NGCCs with CCS could be allowed to demonstrate that they can meet the zero-carbon resource standard under SB100 (which could be done in a number of ways), aligning California with major studies on reaching carbon neutrality that explicitly value carbon removal options including CCS.[32] For example, combining DAC with CCS at an emitting facility could lead to net-zero emissions. DAC deployed on-site could be sized to capture the equivalent of any remaining emissions not captured by CCS. The CO_2 captured by the DAC facility then could be combined into a single CO_2 stream for transport and storage.
- ***Issue guidance for CO_2 storage.*** In California, there is a lack of legal clarity on geologic pore space ownership, creating a thicket of legal issues for potential project developers interested in CO_2 storage. Uncertainty and management of long-term monitoring and stewardship requirements for CO_2 stored for years or decades are an additional, often-cited barrier to CCS project development in the state. The legislature should provide clarity on pore space ownership and state agencies should revise the current long-term monitoring and stewardship requirements under the CCS Protocol to both increase environmental effectiveness and reduce logistical hurdles for project operators.

- ***Develop state supported CCS demos with industry.*** Demonstration projects could provide valuable insights into the technical and regulatory challenges of a CCS project, reducing uncertainty associated with any new and untested process for project developers and regulators. The state should consider supporting a large, state-sponsored CCS demonstration project that could help overcome three major project barriers: high at-risk costs in the project's early stages; untested permitting processes throughout the value chain; and public acceptance of CCS. The state could prioritize projects that have demonstratable local air quality benefits and local job opportunities in line with its climate and equity goals.

California should pursue key enablers for CCS to contribute towards the state's 2045 carbon neutrality goal.

- ***Incorporate CCS Protocol into Cap-and-Trade Program.*** CCS is currently not an eligible pathway under the Cap-and-Trade program or recognized in the Mandatory Greenhouse Gas Reporting Regulation. As a result, covered entities [electricity generators and industrial sources that emit more than 25,000 metric tons CO_2 annually (tCO_2)] cannot use CCS to reduce their compliance obligations (i.e. their annual emissions "cap"), even if they captured and stored their emissions in compliance with the CCS Protocol. In effect, there is no incentive for these covered entities to deploy CCS now or in years to come even though it could contribute large emission reductions. CARB could adopt the CCS Protocol from the LCFS program into the existing Cap-and-Trade Program to provide additional financial incentive for projects to pursue CCS. This is especially important for NGCCs and cement, which are not eligible for LCFS credits but are covered under Cap-and-Trade. The existing CCS Protocol includes several important safeguards for CCS development, requiring that injection wells use the best available methods, the CO_2 storage zone is adequately studied, and long-term leakage risks are mitigated.[33]
- ***Improve support mechanisms to make CCS projects more attractive.*** CCS projects face significant financing headwinds at project onset due to uncertain permitting timelines, finite tax equity appetite, and competition with more widely deployed infrastructure projects. The state could reduce early stage challenges by providing funding support for front-end engineering design (FEED) and/or feasibility studies. Also, California's Congressional delegation could support an extension of the January 2024 deadline to commence construction under the revised federal Section 45Q tax credit. It will likely take as long as six years to develop and deploy a CCS project with a 30-year financing lifespan; the value of the 45Q tax is currently only available for less than half of a facility's likely operating lifetime of a few decades. Providing long-term certainty for 45Q credits could have a transformational impact on CCS project development. Finally, California could consider modifying the LCFS by setting a long-term price floor or other options to increase certainty, providing project developers with the ability to better anticipate its value. In the last eight years, credit prices have ranged from $\$25/tCO_2$ to more than $\$200/tCO_2$.[34,35]
- ***Establish public-private partnerships to create LA and Bay Area hubs.*** This study identified clusters of emissions-intensive facilities (or "hubs") located in in the Los Angeles and San Francisco Bay areas that are suitable candidates for CCS retrofit. Such hubs could dramatically reduce pollution from the large source clusters in these areas. Industrial development tends to form around locations with ample energy supplies and transportation systems (e.g. ports, roads, pipelines). Prioritizing CCS capture hubs for projects that demonstrate local air quality benefits and provide jobs in these areas could help ensure the targeted, concentrated—and possibly more economic—development of a CCS industry compared to a proliferation of point-to-point projects. State sponsorship of FEED and/or feasibility studies could reduce the financial burdens associated with initial development of CCS hubs. Together, these proposed hubs could capture nearly 11 percent of the state's 2017 GHG emissions.[36]

- ***Set statewide carbon removal targets.*** Studies show that reaching economywide carbon neutrality by midcentury or earlier is extremely difficult if not unachievable without major contributions from CDR technologies, a complementary suite of technologies to CCS both in infrastructure and expertise.[37] California is ideally suited to become a leader in CDR policy and technology development given its innovation capacity, skilled workforce in relevant sectors, ambition and progress on climate and clean energy policy, and its natural resource endowment. California's ambitious climate targets provide little guidance on the role for CDR despite its critical role in achieving net-negative emissions. Setting a removal target could help provide direction to state agencies to accelerate the development of new CDR projects that will be needed to achieve the state's carbon neutrality goal. A parallel effort could be for California to develop a process, similar to the one conducted by the National Academies of Sciences in 2019 for its *"Negative Emissions Technologies and Reliable Sequestration: A Research Agenda"* report[38] and EFI in its 2019 study, *"Clearing the Air: A Federal RD&D Initiative and Management Plan for Carbon Dioxide Removal Technologies,"*[39] that determines the eligibility of each potential CDR technology and pathway to meet the state's established carbon removal targets. State agencies could be tasked with developing eligibility requirements for CDR pathways to align policies with emission reduction potential.

California should encourage CCS projects that inspire new opportunities to lead global action on climate.

- ***Support innovation at research institutions and laboratories.*** California has one of the most robust innovation infrastructures in the country. The state should use its substantial resources and innovation capacity to support the demonstration and deployment of new clean energy pathways that rely on or are complementary to CCS and could be replicated in other regions of the country and across the globe. Hydrogen, a clean energy carrier with significant innovation breakthrough potential, could be a focus of California's clean research, development, and demonstration (RD&D). A promising option for developing new hydrogen systems is through regional hubs that include production and the supporting infrastructure for hydrogen storage and distribution. California could establish a "Hydrogen Hub Prize" that seeks actionable and scalable roadmap designs of hydrogen hubs from the state's research institutions and laboratories. DAC is another promising clean pathway that needs more RD&D. DAC removes CO_2 directly from the air instead of from concentrated point sources but requires CO_2 disposition options (i.e. storage or utilization) for it to be a complete carbon removal system. California could commission a multi-user DAC research facility that would provide the state's research institutions a test bed for evaluating ways to reduce the technology's energy, water, and land use requirements. California could also support feasibility studies and demonstration projects that combine point source capture with DAC. This "hybrid" concept offers the potential to create process synergies and is an important area of innovation to help an emitting facility achieve net-zero carbon emissions, facilitating compliance with Cap-and-Trade and SB100.

- ***Support options to ensure adequate clean firm power.*** While there is clearly a need for firm generation to ensure reliability, there is also a need for deep decarbonization of the power sector. Studies show that both these objectives can be achieved by supporting policies to ensure the availability of *clean* firm power generation, which has significant value for cost-effective electricity system reliability under deep decarbonization scenarios. As noted, a recently completed study for California concluded that about 30 GW of clean firm generation would significantly lower the cost for achieving a zero emission grid.[40] This and other studies also conclude that CCS for natural gas combined cycle plants (NGCC-CCS) is one of the most cost-effective approaches for providing clean firm power generation. Policies should be supported that: (1) provide a more precise understanding of how much firm power is needed for a grid that is decarbonizing; (2) inform grid reliability planning processes; (3) identify key technologies for providing clean firm power; and (4) identify policy options, including standards for the scaleup and deployment of those technologies that are essential for ensuring reliable, affordable, and clean power. These policies would not replace technology-neutral power sector emission reduction policies, like a clean energy standard. Instead, it would encourage incremental clean firm deployment where it is most likely to be used and useful in a deeply decarbonized power system, can be designed to be wholly compatible with existing power market and climate policy requirements in the state, and does not raise other significant policy concerns. These policies could be replicated in other regions of the country, adjusted to address and meet local system needs and requirements.
- ***Create CO_2 transport and storage operator.*** Building on the recommendation of large-scale demonstration projects, California could develop a new organization focused on coordinating the CO_2 transport, storage, and administrative operations in a specific region or basin, leveraging state resources such as lands and permitting authorities. The new organization could be modeled on other state entities that manage similar products and activities, such as waste management and disposal. It could be either a private or public entity. This organization could be authorized to manage CO_2 transportation under bilateral contracts where participating customers, such as oil refiners or natural gas-fired power generators, could engage through term contracts that set transparent rates (e.g. fixed or tied to commodity prices) and durations.

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Chapter 1

Meeting California's Decarbonization Targets: The Critical Role of CCS in Carbon Dioxide Removal

This study, "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions," provides policymakers with fundamental actions, key enablers, and opportunities for helping California meet its near-term emissions reduction goals with carbon capture and storage (CCS). CCS can also pave the way for the state's transition to a net-zero emissions economy, enable new industries, and make California a global leader in deploying CCS, a critical subset of carbon dioxide removal (CDR) technologies.

KEY FINDINGS

- California has been experiencing the devastating impacts of climate change for years. Average temperatures across the state are increasing, while Southern California has warmed 3 degrees Fahrenheit (°F) in the last century. In comparison, California warmed approximately 1.5°F over the course of the previous century.
- Several studies have concluded that carbon capture and storage (CCS) and carbon dioxide removal (CDR) could be essential components of California's emission reduction goals by midcentury and that the state will not be able to meet its decarbonization targets without some level of CCS and CDR deployment.
- CCS is a relatively mature clean energy technology that can provide significant greenhouse gas emission (GHG) reductions for California in the near-term. CCS is especially valuable for reducing emissions from high emitting sources, such as industrial facilities, that have few technology alternatives.
- The industrial sector in California contains a large manufacturing base (more than 35,000 firms in 2016) that is also a major job creator, revenue generator, and source of economic value for the state. In 2018, manufacturing accounted for nearly $317 billion in economic value (equivalent to 10.7 percent of the gross state product) and provided jobs for more than 1.3 million employees (equivalent to 7.7 percent of all non-farm employment).
- Several of the state's manufacturing subsectors—chemicals, petroleum and coal products, and plastics and rubber products—are significant contributors to California's economy; they are also supported by the petroleum refining industry in the state, which, with CCS, could continue to play key economic roles while helping to meet the near-term and midcentury climate targets.
- California is the fifth largest economy in the world and has a sizeable industrial workforce. As the state decarbonizes, it must consider the workforce implications of the clean energy transition and the opportunities for creating new industries, such as clean hydrogen and direct air capture (DAC), an important technology for CDR, which also requires geologic storage of CO_2.
- A robust regulatory environment can advance CCS deployment by providing certainty and environmental and safety assurances to CCS developers, investors, and local and regional communities. In contrast, the absence of a sound regulatory environment or one that is unclear and/or unpredictable can act as a barrier to CCS development.
- Globally, of the 21 large-scale CCS projects in operation, five inject carbon dioxide (CO_2) for permanent geologic storage, and 16 inject CO_2 for enhanced oil recovery (EOR). Many projects are expected to come online in the next decade that will offer a wide variety of designs and scale. Expected storage capacity from these in-development large-scale projects ranges from a few hundred thousand tons of CO_2 per year for a relatively small project, to almost 10 million metric tons per year ($MtCO_2$/yr).

Prior to the start of the Global Climate Summit in New York in 2019, California Governor Gavin Newsom signed an executive order to advance California's climate leadership, and announced: "In the face of the White House's inaction on climate change, California is stepping up and leading the way...Our state is proof that you can reach some of the strongest climate goals in the world, while also achieving record economic growth. How we meet this moment will define our state—and country—for decades to come...."[1] On September 23, 2020, Governor Newsom signed an executive order to phase out gasoline-powered cars—a sign that the state is prepared to take aggressive action to deeply decarbonize its major emissions sources.[2]

California is a longstanding U.S. and global leader on environmental actions, including initiatives to deeply decarbonize its economy. These range from the nation's first vehicle emissions standards in 1966, to Governor Newsom's 2019 Executive Order, N-19-19, creating a Climate Investment Framework, using the state's $700 billion retirement program portfolio to drive investment to carbon-neutral technologies.[3] California has also promulgated a comprehensive suite of policies designed to achieve economywide decarbonization by midcentury, while growing the economy and supporting disadvantaged communities.[4,5,6,7]

California has the largest economy in the U.S.; if it were a nation, its economy would rank fifth in the world,[8] behind only the United States, China, Japan, and Germany. As the Governor noted, prior to the coronavirus pandemic, the state's economy grew at a rapid pace alongside the enactment of stringent climate goals. The state's unique policies and the size of its economy place its targets, commitments, and pathways for addressing climate change squarely in the larger global context. This substantially raises the stakes for the success of California's efforts to address climate change—and there is no time to lose.

CALIFORNIA'S URGENT NEED TO ADDRESS CLIMATE CHANGE

The last ten years have been the world's warmest decade in recorded history, and 2019 was the second warmest year on record.[9] In May 2019, atmospheric CO_2 concentration reached 415 parts per million (ppm), the highest level in at least 800,000 years, and at the current rate of warming of 0.2 degrees Celsius (°C) per decade, the planet will likely reach the lower Paris Agreement target of 1.5°C by as early as 2030.

California has been experiencing the devastating impacts of climate change for years. Average temperatures across the state are increasing, while Southern California has warmed about 3°F in the last century.[10] In comparison, California warmed approximately 1.5°F over the course of the previous century.[11] Heat waves are more common. In September 2020, an intense heatwave broke temperature records in several locations, including 121°F in Los Angeles County and 130°F in Death Valley—possibly the hottest temperature recorded on Earth.[12] The extreme heat is contributing to more wildfire outbreaks across large swaths of the state. At the end of September 2020, more than 8,100 wildfires had burned over 3.8 million acres in 2020.[13] The snow is melting earlier in spring—and in Southern California, less rain is falling. Studies show in the coming decades, the changing climate is likely to further decrease the supply of water, increase the risk of wildfires, and threaten coastal development and ecosystems.

California has been experiencing the devastating impacts of climate change for years. Average temperatures across the state are increasing, while Southern California has warmed about 3°F in the last century.

California's Electricity Sector and Economywide Decarbonization Targets

California has a near-term, statutory target of reducing GHG emissions to 1990 levels by 2020[14] and a 40 percent economywide reduction target by 2030 from 1990 levels.[15] In addition, a 2018 law, Senate Bill (SB) 100, requires the state to meet 100 percent of its electricity retail sales with zero-carbon electricity by 2045.[16] Executive Order B-55-18, issued by Governor Brown in 2018 and subsequently endorsed by the Newsom administration, requires economywide carbon neutrality by 2045, and net-negative emissions thereafter.[17] Figure 1-1 shows the state's historic emissions by sector and its economywide climate targets through midcentury.

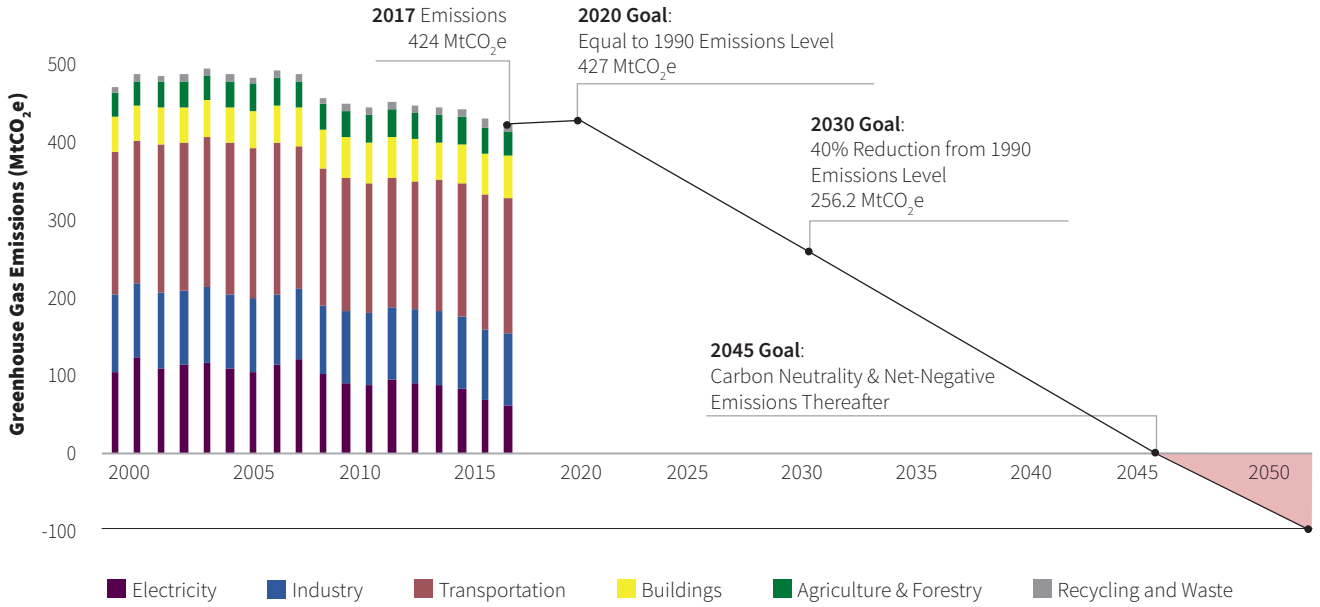
Several studies have concluded that CCS could be an essential component of California's emission reduction goals by midcentury and that the state will likely be unable to meet its decarbonization targets without some level of CCS deployment. A 2011 report by the California Council on Science and Technology (CCST) found that CCS would likely be an important strategy for achieving the state's GHG emission reduction goals under several scenarios, including for the production of hydrogen and low-carbon fuels.[18] The California Air Resources Board (CARB) has also noted that CCS could play an increasingly important role in the state's clean energy ambitions and recognized CCS in its 2017 Climate Change Scoping Plan as a potential pathway for decarbonizing large stationary emission sources.[19]

California's Energy Supply and Demand

This study focuses on how to deploy CCS to lead to rapid decarbonization in California. It does not examine the many potential uses and markets for captured carbon, some of which appear to be longer-term options to reach deep decarbonization. For purposes of this analysis, the International Energy Agency's (IEA) definition of CCS (excluding utilization) is used: "[CCS] refers to a suite of technologies that involves the capture of CO_2 from large point sources, including power generation or industrial facilities that use either fossil fuels or biomass for fuel... the captured CO_2 is compressed and transported by pipeline, ship, rail or truck...[and] injected into deep geological

FIGURE 1-1

CALIFORNIA'S HISTORIC EMISSIONS & FUTURE EMISSION REDUCTION TARGETS



California has already met its 2020 emission reduction target; however, it has increasingly stringent goals in 2030 and by midcentury that require additional technologies, policies, and decarbonization solutions. *Source: Energy Futures Initiative and Stanford University, 2020.*

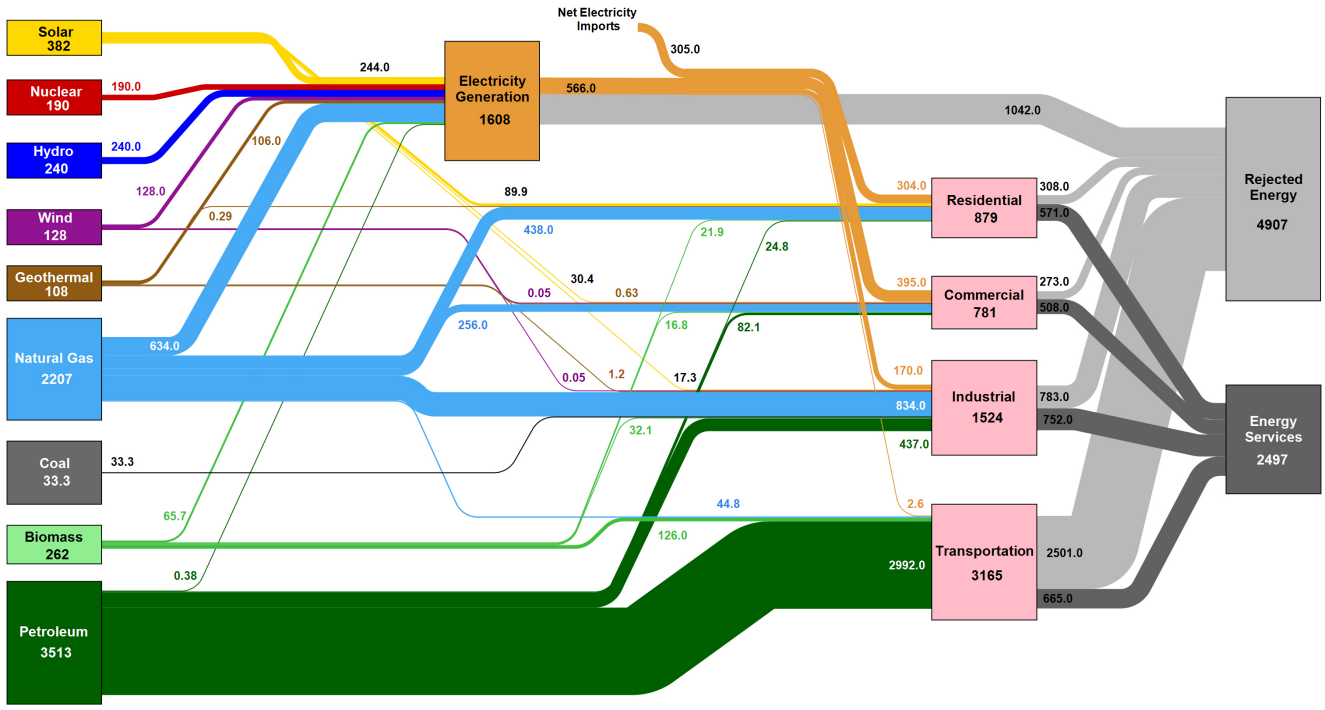
formations (including depleted oil and gas reservoirs or saline formations) which trap the CO_2 for permanent storage."[20] The CCS value chain is discussed in detail in Chapter 2.

The value of CCS for meeting California's emission reduction targets becomes clear when reviewing the state's energy supplies, demand, and end uses. The Sankey diagram of California's energy flows (Figure 1-2)[21] depicts the 2018 energy sources, its mid-stream power generation and energy conversion sources, end uses, imported electricity, and rejected energy.

In 2018, natural gas and petroleum met 78 percent of the state's energy demand. In addition to being the largest fuel source for in-state power generation, natural gas also provides an essential electricity reliability function as it remains a prominent source of firm generation for California. As the power system decarbonizes, the value of firm (and clean) generation,[a,22] should not be underestimated. The May 2020 *Summer Loads and Resources Assessment* by the California Independent System Operator (CAISO), found that meeting net peak in the summer months requires dispatchable generation,

FIGURE 1-2

ESTIMATED CALIFORNIA ENERGY CONSUMPTION, 2018 (TRILLION BTU)



Overall energy consumption in California in 2018 was 7,368 trillion British Thermal Units (BTU), of which 48 percent was from petroleum, 30 percent from natural gas, five percent from solar, three percent from nuclear, three percent from hydropower, one percent from geothermal, one percent from coal, and four percent from electricity imports. *Source: Lawrence Livermore National Laboratory, 2020.*

a The U.S. EIA defines firm power as "power or power-producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions." Clean firm generation includes firm power resources that are low- or zero-emissions, including nuclear, geothermal, biomass, hydro, NGCC-CCS, hydrogen and other carbon free fuels using net-zero processes.

which is currently met with natural gas (60.2 percent of CAISO summer maximum on-peak available capacity) and hydropower (16.3 percent). In comparison, CAISO found that solar accounts for nine percent of summer on-peak available capacity, nuclear is 4.7 percent, wind is three percent, and geothermal is 2.4 percent.[23]

The electricity system is the "uber-infrastructure" of the 21st century, supporting all other critical infrastructures. Grid reliability is central to the state's economy and the health and welfare of its citizens. In 2017, California had 90 days with little to no wind, including several periods of seven-plus days with little to no wind. Variations in hydropower in California have also been significant. In 2015, prolonged drought reduced hydropower to only about seven percent of California's net generation, whereas in 2017, there was significantly more precipitation, increasing hydropower generation to 21 percent; however, in 2018, hydropower dropped again to about 13 percent.[24] Seasonal variation of wind and solar generation is also significant; the difference between peak wind and solar generation in June and their lows in January was 3.2 terawatt-hours (TWh) in 2016. Natural gas has played an essential role throughout these periods of generation variability, both in firming renewables in the short run and ensuring grid reliability over longer periods of time.

Energy consumption by the state's industrial sector was 55 percent natural gas, 29 percent petroleum, 11 percent electricity, and two percent biomass.[25] According to EIA, in 2018, California was the seventh-largest producer of crude oil among the 50 states and, as of January 2019, it ranked third in oil refining capacity.[26] California is also the largest consumer of jet fuel among the 50 states, accounting for one-fifth of the nation's jet fuel consumption in 2018. In short, much of the state's economic activity involves oil and natural gas and their uses by industry, one of the sectors that is most difficult to decarbonize with existing technologies.

Sources of California's Greenhouse Gas Emissions

Total emissions in California in 2017 were 424 $MtCO_2$-equivalent ($MtCO_2e$),[b,27] down by five $MtCO_2e$ from 2016 and seven $MtCO_2e$ below 1990 levels.[28,29] Figure 1-3 shows the sources of these emissions by economic sector and subsector.[30] While they are critical for the state's economy, California's electricity and industrial sectors are the sources of over a third of the state's total GHG emissions.

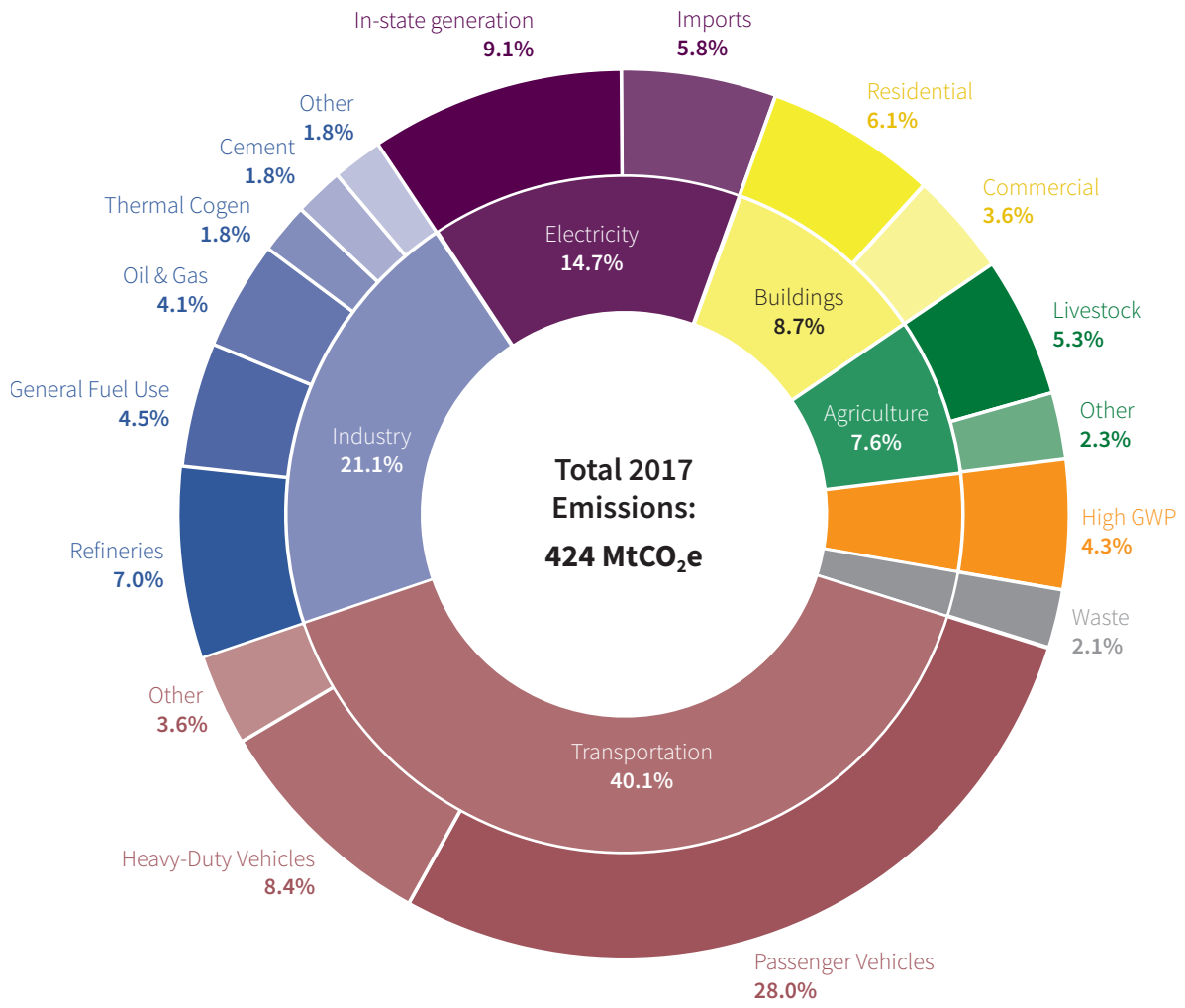
Emissions from California's Electricity Sector

In 2017, the electricity sector accounted for nearly 15 percent of California's total CO_2 emissions, 60 percent of which was from in-state generation resources.[31] As noted, natural gas is the largest source of energy generation in California. According to the California Energy Commission (CEC), natural gas accounted for 35 percent of the state's overall generation mix and 47 percent of its in-state generation mix in 2018.[32]

b The Intergovernmental Panel on Climate Change (IPCC) defines carbon dioxide equivalent (CO_2e) as *"the amount of CO2 emission that would cause the same integrated radiative forcing or temperature change, over a given time horizon, as an emitted amount of a GHG or a mixture of GHGs… most typically, the CO_2-equivalent is obtained by multiplying the emission of a GHG by its global warming potential (GWP) for a 100-year time horizon."* In this analysis, CO_2e is used when discussing economywide GHG emissions, while CO_2 is used when exclusively discussing CO_2 emissions.

FIGURE 1-3

CALIFORNIA GREENHOUSE GAS EMISSIONS BY SECTOR AND SUBSECTOR, 2017



This figure shows California's greenhouse gas emission sources organized by CARB Scoping Plan Category (inner ring) and subsectors (outer ring). Note that totals are rounded. *Source: Energy Futures Initiative and Stanford University, 2020. Adapted from CARB, 2019.*

California's electricity sector currently has one of the lowest emission intensities in the United States because of its lack of coal-fired generation, high penetration of renewables, and relatively newer and more efficient natural gas generation fleet.[33] There are an estimated 195 utility-scale gas-fired units[c] that generate electricity in California, including natural gas combined cycle (NGCC) combustion turbines, combustion turbines, and steam turbines (Table 1-1).[34]

NGCCs are responsible for a majority of the emissions from the power sector in California. In 2018, CARB identified approximately 31 $MtCO_2e$ of emissions from in-state electricity generation resources of which NGCCs were responsible for approximately 80 percent (25 $MtCO_2e$).[35]

Emissions from California's Industrial Sector

The industrial sector has consistently remained a large source of California's emissions. In 2017, industry was

c A utility-scale gas-fired unit is one with a capacity greater than one megawatt (MW).

TABLE 1-1

GAS POWER PLANTS IN CALIFORNIA, 2018

	Units by Prime Mover	Cumulative Nameplate Capacity (GW)	2018 Emissions ($MtCO_2e$)	2018 Average Capacity Factor	2018 Average Age
Combined Cycle Combustion Turbines (NGCC)	48	16.4	25	39%	15
Combustion Turbines	123	8.3	2	6%	12
Steam Turbines	24	6.5	2	4%	56

Distribution of gas power plants in California show that NGCC units have the highest nameplate capacity, emissions, and overall utilization. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Hitachi ABB Velocity Suite.*

responsible for 21 percent of the state's emissions. Within the industrial sector, cement and refining facilities[d] are major emitters. Since 2000, industrial emissions in California have remained relatively steady at around 100 $MtCO_2e$ each year (Figure 1-4).[36] Although the majority of emissions stemmed from fuel combustion, nearly 15 percent were process emissions (i.e., non-combustion) from industrial subsectors including cement production.[37]

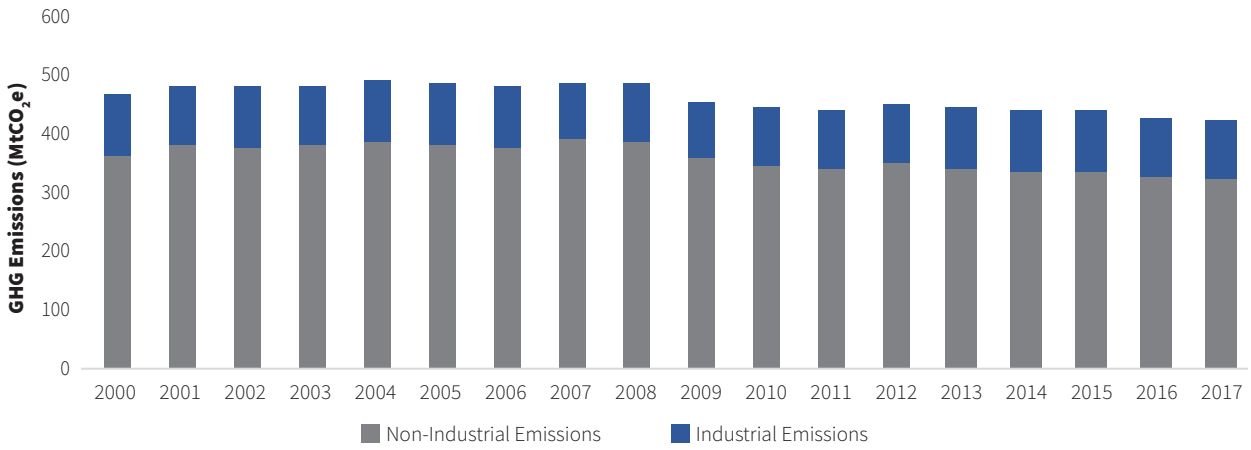
California's nine cement plants together produced about 10 million metric tons (Mt) of cement and emitted 7.9 $MtCO_2e$ in 2015; since that time, one plant has closed. Only 40 percent of emissions from cement plants are from fuel combustion; 60 percent are process related.[38]

Emissions from Wildfires

The effects of climate change are tangible and immediate, especially in California's case. Wildfires are burning through the state at an alarming rate, leading to loss of life,

FIGURE 1-4

INDUSTRIAL SECTOR EMISSIONS IN CALIFORNIA, 2000-2017



Industrial emissions in California have remained relatively constant since 2000. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from CARB, 2020.*

d Refining facilities includes the fluid catalytic cracker unit (FCCU) as well as the combined heat and power (CHP) and hydrogen facilities serving the refinery.

the destruction of property, and the release of significant GHG emissions into the atmosphere. From 2000 to 2019, nearly 334 $MtCO_2$ were emitted from wildfires in the state.[39] As of September 13, 2020, wildfires in California had emitted approximately 83 $MtCO_2$ so far in 2020.[40] That amount is nearly equivalent to California's total industrial sector CO_2-equivalent emissions in 2017.

Wildfires are not going away anytime soon. Nine of California's ten largest fires in recorded history happened within the last decade. As the earth's atmosphere warms, milder winters and less moisture for vegetation creates conditions for wildfires. While the wildfires do not impact state climate goals, the release of CO_2 is still detrimental for the climate, and there are significant negative local air quality impacts.[41] Wildfires also pose an ongoing threat to the state's electricity infrastructure, which is exposed to the increasing impacts of climate change.

Electricity and Industry: Significant Enablers of, and Contributors to, California's Economy

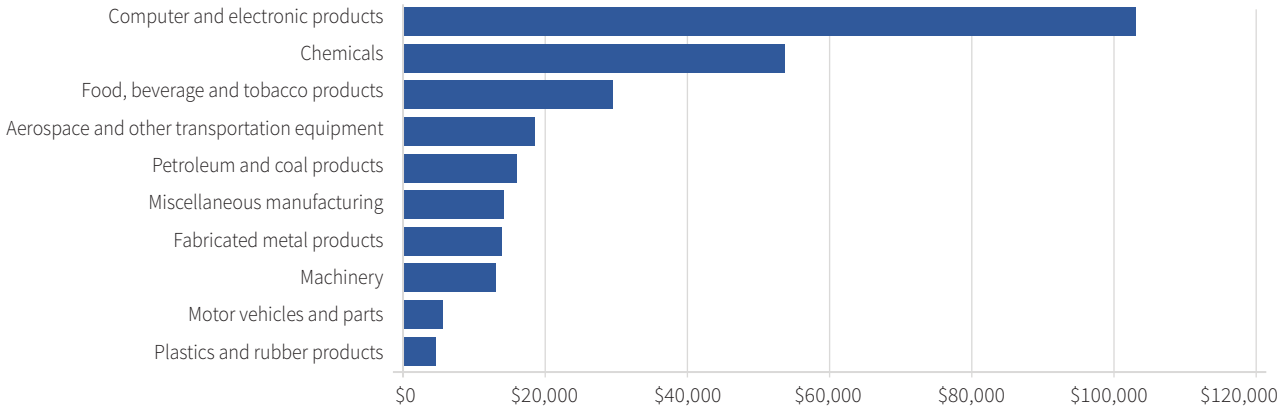
The electricity sector is a critical enabler of the state's economy—supporting all other industries, homes, and activities. It also a major employer in the state; in 2019, California's electric power generation sector employed approximately 180,000 workers, 20 percent of the nationwide total.[42] With increased electrification in key sectors, California's electricity demand is expected to grow approximately 1.6 percent annually through 2030.[43]

The industrial sector in California contains a large manufacturing base (more than 35,000 firms in 2016) that is a major job creator, revenue generator, and source of economic output for the state. In 2018, manufacturing accounted for nearly $317 billion in economic output (equivalent to 10.7 percent of the gross state product) and provided jobs for more than 1.3 million employees (equivalent to 7.7 percent of all non-farm employment).[44] As seen in Figure 1-5,[45] several manufacturing subsectors—chemicals, petroleum and coal products, and plastics and rubber products—are significant contributors to California's economy; they are also supported by petroleum refining, point sources of emissions that could, with CCS, continue to play key economic roles in the state while reducing emissions in line with the state's near-term and midcentury climate targets.

Natural gas is used in many manufacturing processes and products. Some examples: natural gas is used as a feedstock for chemical and hydrogen production, as well as for fuel for process heat for manufacturing and industrial processes.[46] It is also used in glass melting, food processing, fertilizer production, plastics, and pharmaceuticals.

FIGURE 1-5

TOP 10 CALIFORNIA MANUFACTURING SECTORS, OUTPUT IN MILLIONS OF DOLLARS, 2017



Chemicals, petroleum and coal products, and plastics and rubber products are significant contributors to California's economy; they are also supported by the petroleum refining industry. *Source: National Association of Manufacturers, 2020.*

California is also the second-largest cement producing state in the United States. The cement industry in California is a major employer and revenue generator (Figure 1-6).[47] The cement and related industries contribute almost $14 billion to state's economy. It is also a significant source of state revenues, paying over $308 million in state taxes in 2018.[48]

In addition to being a major enabler of the state's electricity and industry sectors, the oil and gas industry is a major employer and source of economic activity. In 2015, it employed almost 370,000 people (1.6 percent of the workforce) and represented 2.7 percent of the gross state product.[49] California has 15 refineries, and oil and petroleum products are major sources of revenues at its nearly 100 marine, tanker, barge, pipeline, rail, or truck terminals.[50] The Marathon Refinery in Los Angeles, for example, produces gasoline, diesel fuel, distillates, petroleum coke, anode-grade coke (after processing used for aluminum and steel production), chemical-grade propylene, fuel-grade coke, heavy fuel oil and propane. Its Watson cogeneration plant produces 400 MW and is the largest cogeneration facility in California.[51]

CCS Can Provide Near-Term Emission Reductions in California

To help identify options for meeting California's near-term emissions reduction goals and enabling longer term deep decarbonization, the Energy Futures Initiative (EFI) released a comprehensive study in May 2019, *Optionality, Flexibility, and Innovation: Pathways for Deep Decarbonization in California.*[52] This analysis identified currently available technologies that could help the state meet its near-term target of 40 percent economywide emissions reductions by 2030 and assessed their emission reduction potential based on a range of specific California factors and needs.[e]

According to EFI's analysis, CCS has the potential to be the largest source of emission reductions by 2030 for both the electricity and industrial sectors. An initial analysis, without further screens and other inputs, showed that

FIGURE 1-6

CALIFORNIA'S CEMENT INDUSTRY: EMPLOYEES, REVENUES, AND LOCATIONS

	California		National
	Cement	Cement & Related	Cement
Employees	1,449	16,774	12,229
Payroll ($)	100,981,280	923,889,968	$1.1 billion
Contribution to State Taxes Revenues ($)	35,580,242	411,854,285	270,813,634
Economic Contribution ($)	2,422,638,273	12,132,486,307	15,444,948,970

California's cement industry is a major employer and contributor to the state's economy; it is also a significant source of greenhouse gas emissions. *Source: Adapted from Portland Cement Association, 2017*

e For purposes of the analysis, EFI assumed a 2016 baseline, not the 1990 baseline in CA law; total emissions were almost identical, and many new technologies and emissions sources have been identified since 1990, e.g. high GWP emissions. EFI also allocated emissions reduction needs across each emitting sector of the state's economy based on their share of 2016 emissions.

CCS had the potential to meet 18 percent of California's total reductions needed to meet its 2030 target. EFI's 2019 analysis identified emitters that might be good targets for carbon capture as well as potential geologic storage sites in California. Figure 1-7 shows the 33 technology pathways identified and their potential for meeting the state's targets in the 2030 timeframe.

The significant value of industry and electricity to California's economy noted above, coupled with their contributions to the state's emissions, suggests that solutions are needed to both enable the ongoing economic value and dramatically reduce their emissions in the near- and longer-term. These solutions should also enable the clean energy transtion to, for example, a hydrogen economy and direct air capture (DAC) with CO_2 storage, pathways that could play major roles in meeting the state's carbon neutrality by 2045 goal.

While the opportunity to leverage CCS to deeply decarbonize is significant, realizing its potential requires immediate action as project development, planning, permitting, and construction takes several years and every year counts for meeting the imperatives of climate change.

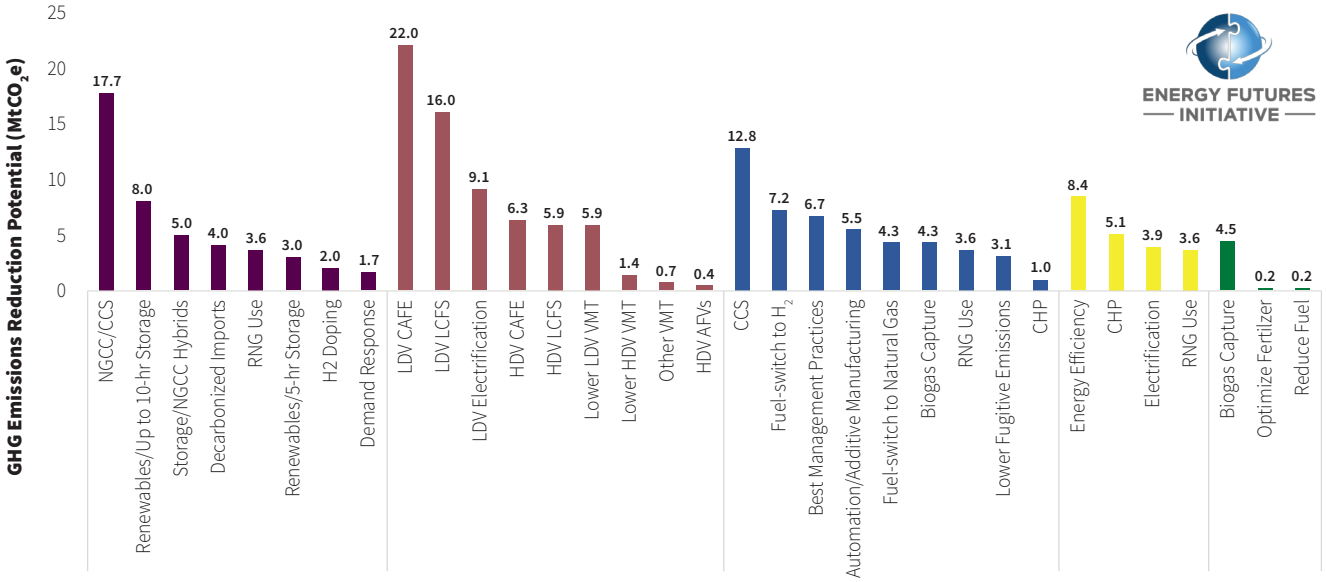
MEETING GLOBAL CLIMATE TARGETS UNDERSCORES THE NEED FOR CCS

The world is currently on a trajectory to exceed 3°C by midcentury, accelerating the need to deploy the full arsenal of options for reducing emissions to keep global temperature increases to 2°C or less. Waiting is no longer an option. According to the Executive Director of the United Nations Environment Program, "Our collective failure to act early and hard on climate change means we now must deliver deep cuts to emissions... We need quick wins to reduce emissions as much as possible in 2020, then stronger Nationally Determined Contributions to kick-start the major transformations of economies and societies. We need to catch up on the years in which we procrastinated... If we don't do this, the 1.5°C goal will be out of reach before 2030."[53]

Analysis by the IEA reinforces the need for and value of "quick wins" to meet climate targets. Under the Sustainable Development Scenario in the IEA 2019 World Energy Outlook, "technologies at the mature and early adoption phases deliver almost two thirds of the midcentury reductions..." Another IEA study released in

FIGURE 1-7

IDENTIFIED EMISSIONS REDUCTION POTENTIAL OF PATHWAYS FOR MEETING CALIFORNIA'S 2030 TARGET IN PREVIOUS EFI STUDY



EFI estimated the emission reduction potential for each pathway by sector to meet California's economywide target of reducing emissions 40 percent by 2030. *Source: Energy Futures Initiative, 2019.*

2020 concludes that to meet the goals of its Sustainable Development Scenario relative to its Stated Policies Scenario (which assumes nations of the world meet their Paris targets) by 2050, nine percent of reductions will come from CCS among a complement of other mature technologies (Figure 1-8).[54]

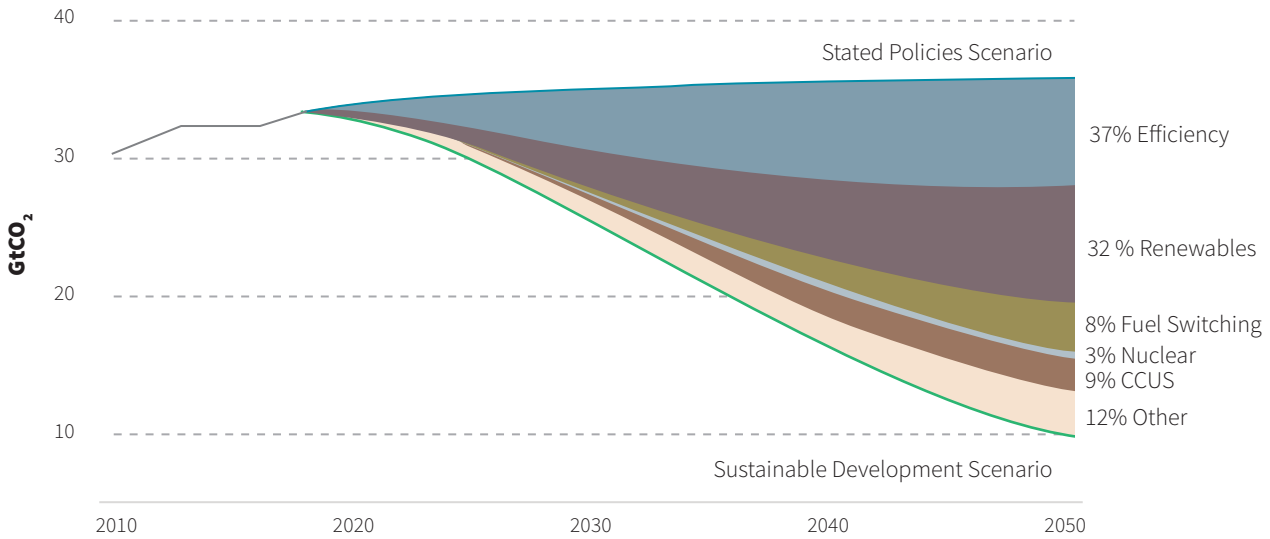
In this regard, IEA estimates that the world will need to reach an industrial CCS capacity of 450 $MtCO_2$ per year by 2030 to be consistent with the goals of the Paris Agreement.[55] According to the IEA, CCS is also key to emission reductions in specific industrial subsectors: CO_2 capture is the key near-zero technology option for the cement sector, and CCS could reduce direct emissions from cement manufacturing—both from process heat and calcination by 95 percent.[56] From its recently released study of global carbon capture, utilization, and storage (CCUS) needs and opportunities, IEA concludes that, CCUS

> "will need to form a key pillar of efforts to put the world on the path to net-zero emissions. A net-zero energy system requires a profound transformation in how we produce and use energy that can only be achieved with a broad suite of technologies. Alongside electrification, hydrogen, and sustainable bioenergy, CCUS will need to play a major role. It is the only group of technologies that contributes both to reducing emissions in key sectors directly and to removing CO_2 to balance emissions that cannot be avoided—a critical part of "net" zero goals."[57]

According to the Executive Director of the United Nations Environment Program, "Our collective failure to act early and hard on climate change means we now must deliver deep cuts to emissions... We need quick wins to reduce emissions as much as possible in 2020...We need to catch up on the years in which we procrastinated... If we don't do this, the 1.5°C goal will be out of reach before 2030."

FIGURE 1-8

TECHNOLOGIES NEEDED TO MEET IEA'S 2050 SUSTAINABLE DEVELOPMENT GOALS

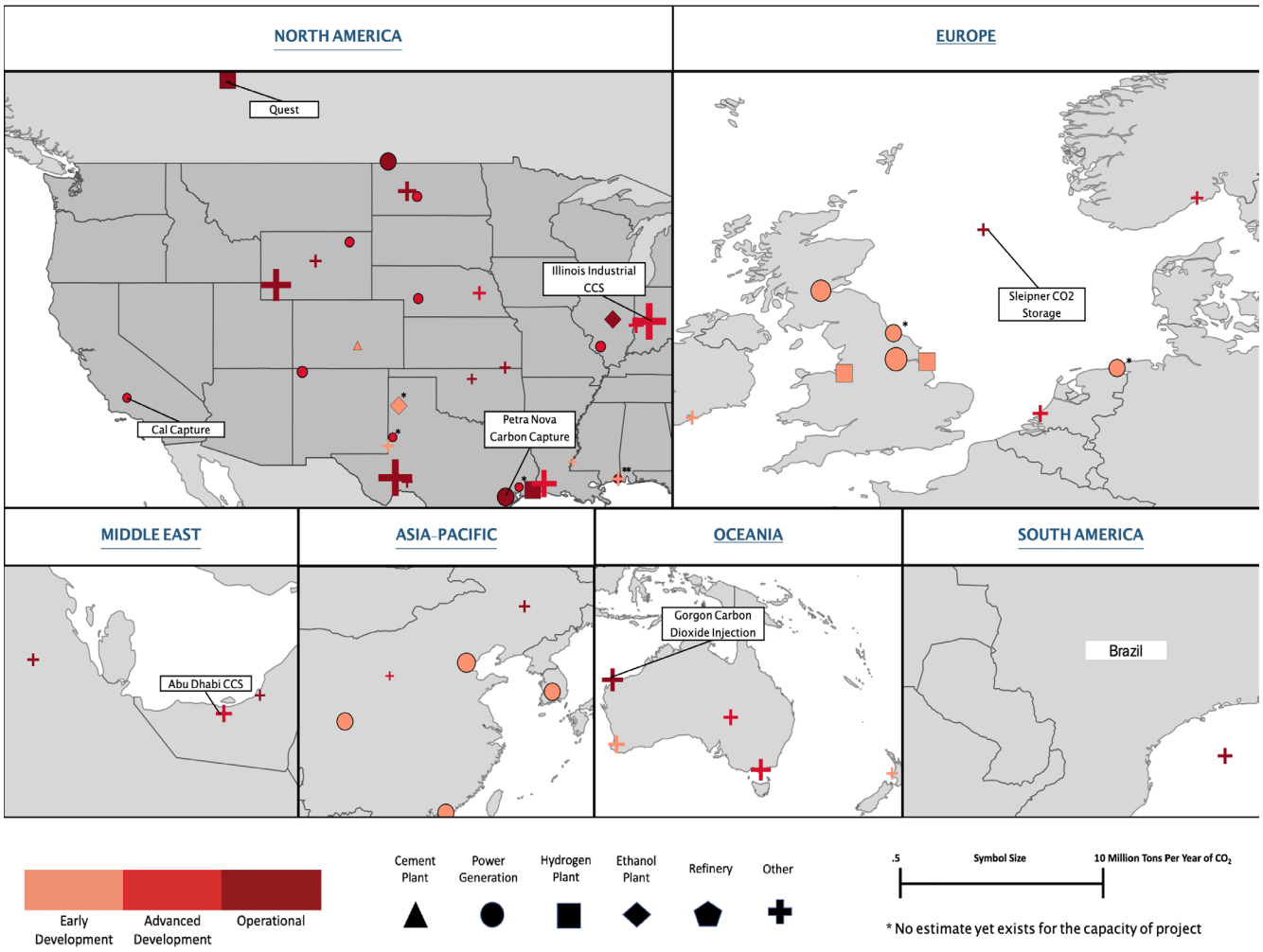


This figure shows the emissions reductions by technology category in the IEA's Sustainable Development Scenario relative to its Stated Policies Scenario; this includes a nine percent share of CCUS. *Source: International Energy Agency, 2019.*

Storing CO_2 in saline reservoirs for the purpose of reducing GHG emissions began in 1996 with the Sleipner CO_2 storage project in Norway. Since the project began, it has captured and permanently stored more than 16 $MtCO_2$.[58] The global CCS industry continues to develop. As of September 2020, there were 61 large-scale CCS facilities that were operational, in advanced development (i.e. under construction or in an advanced planning stage), or in early development (i.e. early planning), according to the Global CCS Institute (Figure 1-9).[59] The 21 operating projects have the capacity to capture and store 38 $MtCO_2$/yr, or roughly the emissions from California's commercial and residential buildings sector in 2017 (38.7 $MtCO_2e$).[60] On average, global CCS deployments have grown at a rate of nine percent per year over the past two decades.[61] This rate needs to double to about 17 percent per year to achieve emissions

FIGURE 1-9

CCS PROJECTS ACROSS THE GLOBE, SEPTEMBER 2020



Globally, CCS projects have operated since the 1990s with 21 large-scale projects in operation as of September 2020, and 40 in various stages of development. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Global CCS Institute, 2020.*

reductions on the order of five gigatons (Gt) per year[f] by midcentury.[62,63]

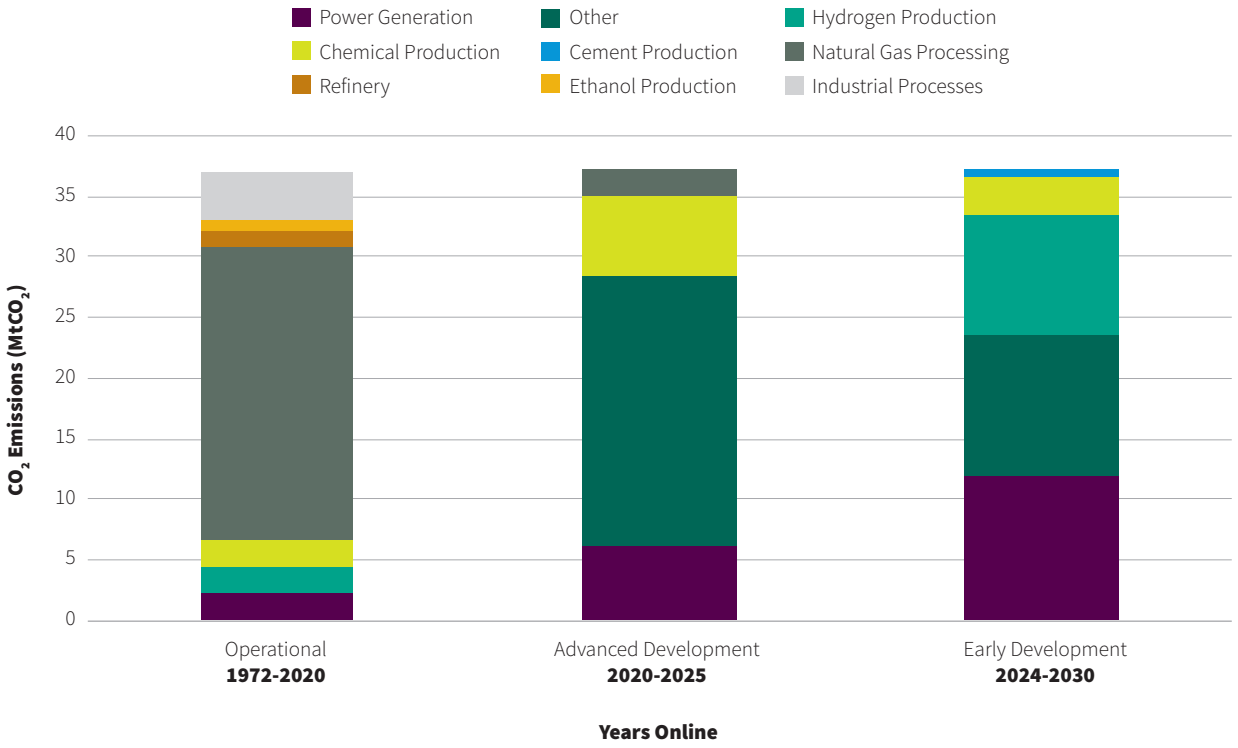
Globally, most carbon capture projects are on natural gas processing facilities, which remove co-produced, naturally occurring CO_2 from natural gas to make pipeline quality natural gas.[64,65] Industrial processes[g] are the second largest source of captured emissions, and there is a growing number of CCS projects for power generation, hydrogen production, and ethanol production (Figure 1-10). The U.S., United Kingdom, Australia, and China are focused on developing CCS projects over the next several years.

Almost all of the large-scale facilities currently in operation around the world rely on pipelines to transport CO_2 from point sources of emissions to storage sites; there is currently a network of over 4,000 miles of pipelines that transport captured CO_2 to CO_2 storage sinks.[66] Some projects that are currently under development, however, such as the Northern Lights project in Norway[67] and the Korea CCS project in the South Korea,[68] contemplate marine shipping as opposed to piping CO_2 for storage or use.

Globally, of the 21 large-scale CCS projects in operation, five inject CO_2 for permanent geologic storage, and 16 inject CO_2 for enhanced oil recovery (EOR). In addition, many projects are expected to come online in the next decade that will offer a wide variety of designs and scale.

FIGURE 1-10

PIPELINE OF CCS PROJECTS WORLDWIDE, BY INDUSTRY APPLICATION



The largest number of operational projects are gas processing facilities. Projects currently in advanced development are for power generation, chemical production, and from multiple sources. Projects in early development are largely for power generation, and chemical, hydrogen and cement production. Note: this graphic only accounts for plants with established or forecasted amounts of capture; the actual amount may be greater. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Global CCS Institute, 2020.*

f 5 Gt/yr is the amount of emission reductions from CCS needed in the IEA's Clean Technology Scenario to limit warming to two degrees Celsius by 2060.

g Industrial processes include the production of fertilizer, chemicals, steel and iron, and methanol

Globally, of the 21 large-scale CCS projects in operation, five inject CO_2 for permanent geologic storage, and 16 inject CO_2 for EOR... many projects are expected to come online in the next decade that will offer a wide variety of designs and scale. Expected storage capacity from these in-development large-scale projects ranges from a few hundred thousand tons of carbon per year for a relatively small project, to almost 10 million tons per year.

Expected storage capacity from these in-development large-scale projects ranges from a few hundred thousand tons of carbon per year for a relatively small project, to almost 10 $MtCO_2$/yr for the largest projects in consideration. Among the seven non-U.S. projects "in construction" or "advanced development," three intend to use the CO_2 for EOR, while the other four have plans for permanent geologic storage.[69] Figure 1-11 shows the cumulative growth of CO_2 storage by emission source.[70]

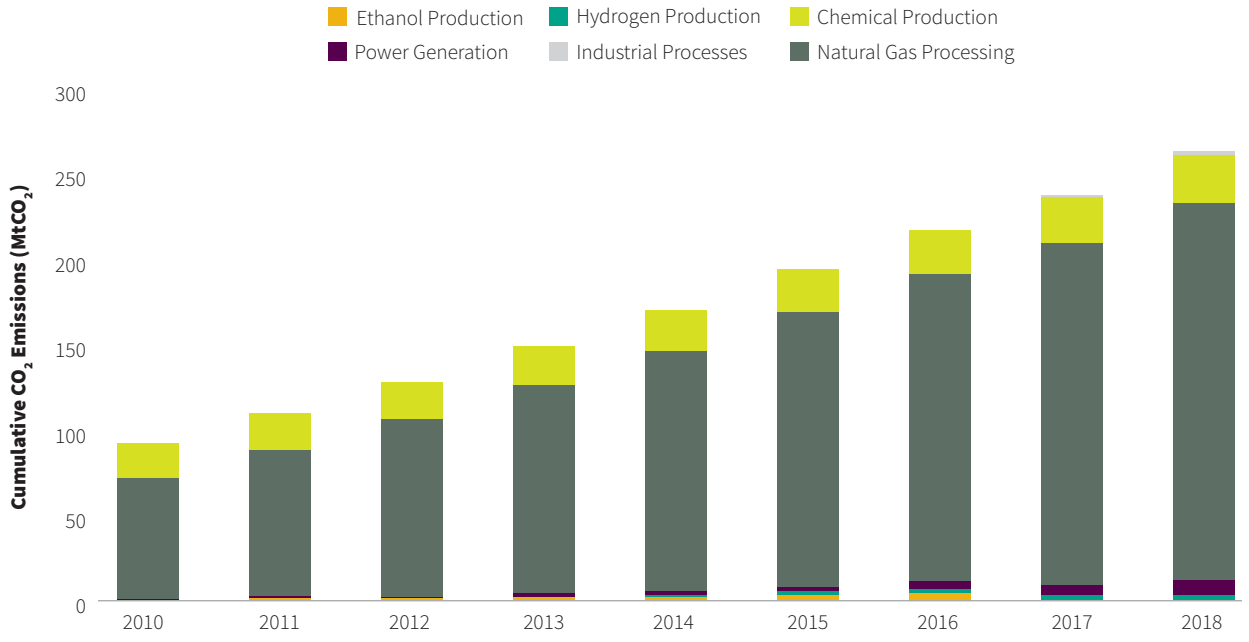
Global Approaches to Policy and Regulatory Support for CCS

Recognizing the long-term value of geologic carbon storage to lower emissions, governments around the world are developing regulatory structures to support CCS development. A robust regulatory environment can advance CCS deployment by providing certainty and environmental and safety assurances to CCS developers, investors, and local and regional communities.

In contrast, the absence of a sound regulatory environment or one that is unclear and/or unpredictable can act as a barrier to CCS development. The consequences of an unpredictable regulatory process include significant preconstruction delays, lack of confidence in the project by stakeholders, compliance challenges, and difficulty in attracting project investment. Indeed, the lack of clarity regarding operators' financial contributions and ability to transfer liabilities has led to the collapse of CCS projects like the ROAD offshore storage plan in the Netherlands.[71]

FIGURE 1-11

CUMULATIVE CO_2 STORED GLOBALLY BY SOURCE, 2010-2018



From 2010-2018, stored CO_2 was largely from natural gas processing facilities. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Global CCS Institute, 2020.*

Given the expansion of CCS projects globally, there are a number of examples of regulatory environments, including environmental requirements, that provide valuable examples both for the development of new CCS programs and opportunities to reform or modernize existing ones. Figure 1-12 shows the policy environment and project characteristics of a variety of CCS projects around the world.[72]

Norway has one of the most advanced CCS regulatory regimes, having conducted CCS operations since the implementation of a carbon tax in the 1990s.[73] In some respects, Norway is readily able to adjust its CCS policies, as the government controls all entities involved. State-owned petroleum company, Equinor, owns and operates carbon storage sites,[74] while state-owned Gassnova is an enterprise specifically focused on developing and

FIGURE 1-12

POLICY ENVIRONMENT AND LEGAL CHARACTERISTICS OF CCS PROJECTS AROUND THE WORLD

Policies & project characteristics	Carbon tax	Tax credit or emissions credit	Grant support	Provision by government or SOE	Regulatory requirement	Enhanced oil recovery	Low cost capture	Low cost transport and storage	Vertical integration
US									
Terrell						○	●	●	
Enid Fertiliser						○	●	●	
Shute Creek					●	○	●	●	
Century Plant		●				○	●		
Air Products SMR		●	○			○			
Coffeyville		●				○	●		
Lost Cabin		●				○	●		
Illinois Industrial		●	○				●	●	●
Petra Nova		●	○			○			
Great Plains						○	●		
Canada									
Boundary Dam			○	●	●	○		●	
Quest		●	○						●
ACTL Agrium			○			○	●		
ACTL Sturgeon			○			○	●		
Brazil									
Petrobras Santos				●		○	●	●	●
Norway						○			
Sleipner	●			●			●	●	●
Snøhvit	●			●	●		●		●
UAE									
Abu Dhabi CCS				●		○		●	
Saudi Arabia									
Uthmaniyah				●		○	●	●	●
China									
CNPC Jilin				●		○	●	●	●
Sinopec Qilu*				●		○	●	●	
Yanchang*				●		○	●		
Australia									
Gorgon			○		●		●	●	●

This table shows the policy levers and conditions that have accelerated CCS development and deployment around the world. Note: SOE in the fifth column stands for State Owned Enterprise. *Source: Global CCS Institute, 2019.*

economizing CCS projects;[75] both of these enterprises are able to advise the Norwegian Ministry of Petroleum and Energy on how to modify policy to effectively achieve Norway's climate goals. The Ministry of Petroleum and Energy regulates most CCS activities, though the Ministry of Environment and Climate regulates injection processes. Some aspects of the value chain may require interaction with the Ministries of Transport, Labour & Social Affairs (Figure 1-13).[76,77]

In Australia, Chevron's Gorgon natural gas project is largely governed by the State of Western Australia. The regulations governing this project are tailored specifically to match its features and needs. The Gorgon natural gas field contains large amounts of CO_2, and a condition of its development was that at least 80 percent of its extracted CO_2 would be stored in secure geological formations in accordance with Western Australia's Barrow Island Act[78] as well as the project's development permit.[79] Monitoring and liability requirements are particular to the Gorgon gas project[80] and not generalized to other CCS projects. The project is still subject to some general oversight by the Australian Federal Government, such as emissions reporting to the Clean Energy Regulator.[81]

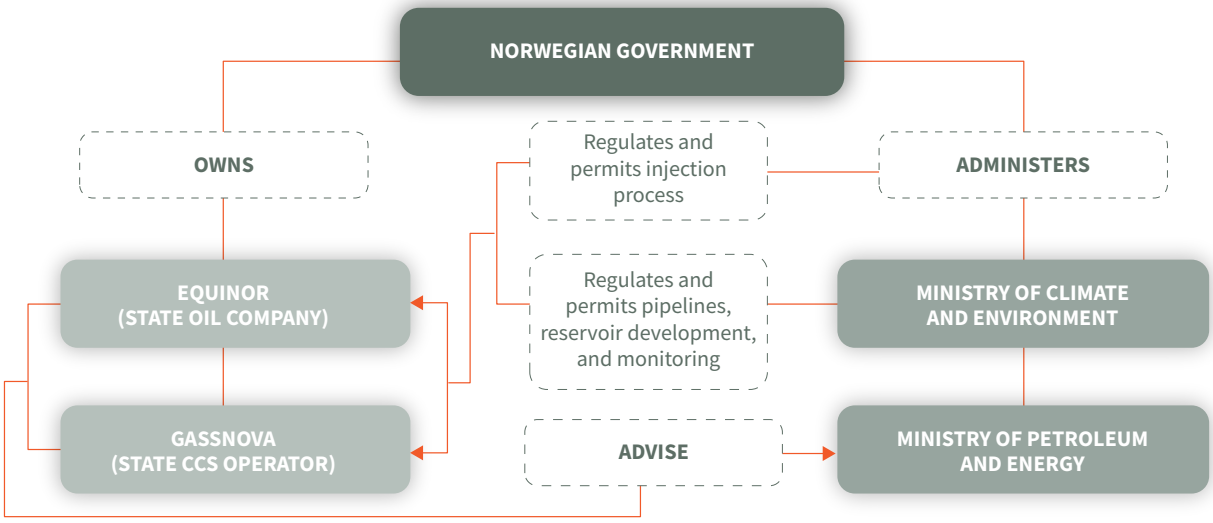
In Canada, CCS regulations are also largely enacted at the provincial level. The CCS retrofit on the Boundary Dam coal plant in Saskatchewan is governed primarily by Saskatchewan's Oil and Gas Conservation Act,[82] which established standards for drilling, injection, and monitoring. Although the Canadian federal government has established its own standards for environmental protections, it may establish "equivalency agreements," which allow provincial regulations to supersede; Saskatchewan has achieved such an equivalency agreement on GHG emissions from coal-fired electricity generation, allowing for the development of Boundary Dam.[83]

CCS IN THE UNITED STATES

The U.S. is a world leader in CCS, though the majority of projects use the captured CO_2 for EOR and not geologic storage in saline formations. It has ten large-scale, operational projects with a total storage potential of 25

FIGURE 1-13

NORWAY'S GOVERNANCE STRUCTURE FOR CCS



Norway's state-owned CCS industry has safely regulated and operated CCS projects since 1996. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Norwegian Ministry of Petroleum and Energy, 2015 and Gassnova, 2020.*

$MtCO_2$/yr as well as 18 additional large-scale projects in various stages of development.[h] Much like their global counterparts, U.S. facilities have a range of capture potential, with capture capacities ranging from hundreds of thousands to millions of tons of CO_2 per year. Table 1-2[84,85] shows that of the operational large-scale CCS projects, nine involve industrial sector applications and one is in the electricity sector.[86]

TABLE 1-2

OPERATIONAL CCS PROJECTS IN THE UNITED STATES, AUGUST 2020

Facility Name	State	Operating Year	Capture Capacity ($MtCO_2$/yr)	Transport	Sink Type	Emissions Source Subsector
Air Products Steam Methane Reformer	TX	2013	1	12-mile pipeline	EOR	Hydrogen production
Century Plant	TX	2010	8.4	27-mile pipeline	EOR	Natural gas processing
Coffeyville Gasification Plant	KS	2013	1	70-mile pipeline	EOR	Fertilizer production
Enid Fertilizer	OK	1982	0.7	140-mile pipeline	EOR	Fertilizer production
Great Plains Synfuels Plant and Weyburn-Midale	ND	2000	3	205-mile pipeline	EOR	Synthetic natural gas
Illinois Industrial Carbon Capture and Storage	IL	2017	1	1-mile pipeline	Geologic	Ethanol production
Lost Cabin Gas Plant	WY	2013	0.9	232-mile pipeline	EOR	Natural gas processing
Shute Creek Gas Processing Plant	WY	1986	7	30-mile pipeline[i]	EOR	Natural gas processing
Terrell Natural Gas Processing Plant	TX	1972	0.4-0.5	83-mile pipeline	EOR	Natural gas processing
Petra Nova Carbon Capture[j]	TX	2017	1.4	80-mile pipeline	EOR	Power Generation (coal-fired)

The majority of operational carbon capture facilities in the U.S. are on industrial sources; there is only one capture project in the electricity sector. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Global CCS Institute, 2020.*

h This includes large-scale, U.S. projects in advanced development, early development, and in construction, as categorized on the Global CCS Institute's CO_2RE public Facilities Database.

i The pipeline from Shute Creek merges into a larger pipeline throughout Wyoming.

j Since the collapse in oil prices amidst the coronavirus recession, it has not been economical to use captured carbon for the EOR activities associated with Petra Nova coal plant, so its carbon capture unit has not been operating. From a technical perspective, however, the equipment is still functional and capable of capturing CO_2.

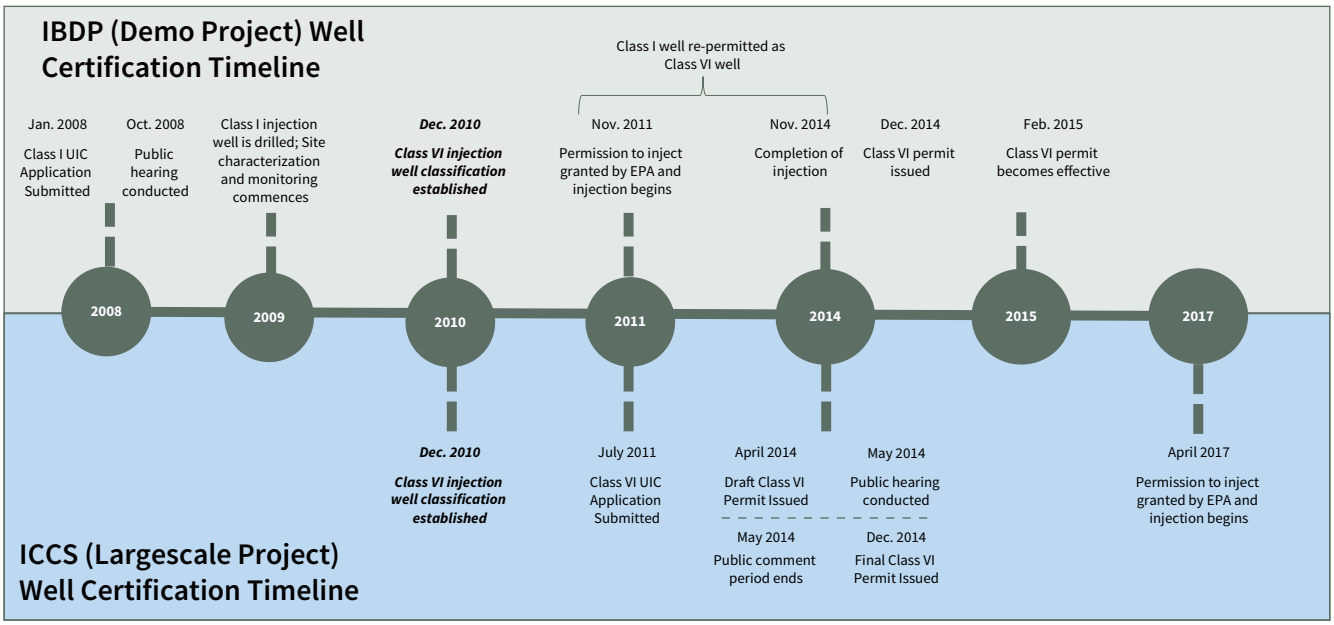
Industrial sources have higher concentrations of CO_2 in the flue gas streams (e.g., 30 percent concentration by volume for cement plants)[87] relative to power plants (e.g., 15 percent and five percent CO_2 concentration for coal- and natural gas-fired power plants, respectively), making industrial sources more cost-effective for capture.[88]

There is existing CO_2 pipeline infrastructure in Texas, Wyoming, Montana, North Dakota, Colorado, New Mexico, Louisiana, and Mississippi.[89] Although these pipelines largely deliver naturally-occurring CO_2 from natural reservoirs to EOR end users, there are operational carbon capture facilities in these regions that supply CO_2 via pipeline to monetize it for use in EOR operations.[90] Additional pipelines will, however, be necessary as the number of CCS projects increase in other regions.

The only CCS project utilizing permanent geologic storage (i.e. deep saline reservoir) in the U.S. is the Illinois Industrial Carbon Capture and Storage (ICCS) project. This project is the first to complete the U.S. Environmental Protection Agency's (EPA) Class VI injection well certification process, which is required by the Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) program.[k] The goal of the UIC program is to protect underground sources of drinking water. ICCS is an extension of the Illinois Basin Decatur Project (IBDP) demonstration, which stored nearly one $MtCO_2$ from November 2011 to November 2014. ICCS began capture and storage operations in April 2017, upon receiving the finalized Class VI permit for injection.[91] The permitting processes for the ICCS and IDBP projects is described in Box 1-1.

BOX 1 FIGURE 1

TIMELINES FOR PERMITTING THE FIRST TWO UIC CLASS VI WELLS



ADM's IBDP demonstration project received a Class VI well after three years of re-permitting from its Class I designation. It took the large-scale ICCS project nearly six years to fully permit its Class VI well. *Source: Energy Futures Initiative and Stanford University, 2020.*

k UIC Class VI permits are those required for the underground injection of CO_2 for the purposes of permanent geologic storage; UIC Class II permits are required for EOR. The UIC program and injection well permits are described in detail in Chapter 2.

BOX 1-1

LESSONS ON UIC PERMITTING: ILLINOIS INDUSTRIAL CARBON CAPTURE AND STORAGE PROJECT

Archer-Daniels-Midland (ADM) Company, based in Decatur, Illinois, is the first company in the U.S. to develop a CCS project that injects the CO_2 for dedicated geologic storage.[92] In 2007, DOE provided funding for ADM to pursue a CCS demonstration project, known as the Illinois Basin Decatur Project (IBDP), which captured one $MtCO_2$ from its ethanol production facility over the course of three years.[93] The IBDP demo provided substantial technical knowledge and permitting experience that enabled ADM to pursue a large-scale CCS project with dedicated geologic storage that still operates today, the Illinois Industrial Carbon Capture and Storage (ICCS) project.[94]

In January 2008, ADM applied for a UIC Class I injection permit (rather than the Class VI permit) for the IBDP injection well because the Class VI program did not yet exist.[l,95,96,97] It took nearly five years for EPA Region 5 to authorize the Class I well for the IBDP; the project began storing CO_2 in November 2011.[98] Approximately one month after ADM began injecting CO_2 under its Class I permit, it applied for a Class VI permit (using information from the Class I permit) to transition the well from Class I to the newly-created Class VI designation. Transitioning to a Class VI well enabled ADM to get experience and increase its understanding of the post-injection site care requirements needed for Class VI wells, highly valuable data used to inform ADM's permanent large-scale CCS operation, the ICCS project.

DOE awarded a total of $141 million (first in October 2009, then in June 2010) for ADM's ICCS project, which captures CO_2 from the same ethanol facility used for the IBDP demonstration and also injects the CO_2 into the same geologic formation, the Mount Simon Sandstone.[99] In July 2011, ADM applied for a Class VI permit for ICCS, which was not authorized by the EPA until February 2015.[100] Even so, EPA modified the permit for the ICCS well after well construction and pre-injection testing.[101] In April 2017, the UIC Class VI permit was finalized, authorizing the project to begin injection.[102,103]

IBDP took approximately four and a half years to receive a Class I permit and more than three additional years to re-permit its Class I well as a Class VI well. ICCS had the first well completely authorized under the Class VI program, and the process took nearly five and a half years to complete before injection could begin. ADM's experience implementing the IBDP demo proved helpful for scaling up to the large-scale ICCS project from both a technological and regulatory perspective; however, to date, ICCS remains the only project to successfully navigate the Class VI process, highlighting a major area of uncertainty for project developers seeking to pursue permanent geologic storage.[104]

l UIC Class I wells are required to inject hazardous and non-hazardous wastes into deep, confined rock formations. Before the UIC Class VI program was established in 2010, the EPA issued a Class I well permit to ADM for the IBDP to inject CO_2 for permanent geologic storage.

Federal Support for CCS Projects in the United States

Projects in the U.S. have benefitted from significant federal funding from the U.S. Department of Energy (DOE). Most recently in September 2020, DOE awarded nearly $51 million for carbon capture research and development (R&D) and nearly $21 million for DAC R&D.[105] In September 2019, DOE awarded $110 million across three funding opportunities to support a range of technologies within CCUS.[106,m]

Section 45Q Tax Credit

The U.S. Tax Code Section 45Q tax credit is a tax incentive for dedicated geological CO_2 storage, CO_2-EOR, or CO_2 utilization. The 45Q tax credit was established in 2008 and amended in the Bipartisan Budget Act of 2018. The amended 45Q provides tax credits for dedicated geologic storage of $34 USD per ton of CO_2 (tCO_2) in 2020, increasing to $50/$tCO_2$ in 2026, then inflation adjusted. For EOR and other means of CO_2 utilization, the tax credits are $22 USD/$tCO_2$ in 2020, increasing to $35/$tCO_2$ in 2026, then inflation adjusted (Figure 1-14).[107,108]

FIGURE 1-14

45Q TAX CREDIT VALUE AVAILABLE FOR DIFFERENT SOURCES AND USES OF CO_2

	Minimum Size of Eligible Carbon Capture Plant by Type ($ktCO_2$/yr)			Relevant Level of Tax Credit in a Given Operational Year ($USD/$tCO_2$)									
Type of CO_2 Storage/Use	Power Plant	Other Industrial Facility	Direct Air Capture	2018	2019	2020	2021	2022	2023	2024	2025	2026	Beyond 2026
Dedicated Geological Storage	500	100	100	28	31	34	36	39	42	45	47	50	Indexed to Inflation
Storage via EOR	500	100	100	17	19	22	24	26	28	31	33	35	
Other Utilization Processes[1]	25	25	25	17[2]	19	22	24	26	28	31	33	35	

[1] Each CO_2 source cannot be greater than than 500 $ktCO_2$/yr
[2] Any credit will only apply to the portion of the converted CO_2 that can be shown to reduce overall emissions

The amended 45Q provides tax credits for dedicated geologic storage of $34 USD/$tCO_2$ in 2020 increasing to $50/$tCO_2$ in 2026, then inflation adjusted. *Source: Energy Futures Initiative, 2018. Closely adapted from Simon Bennett and Tristan Stanley.*

m The first was $55.4 million across nine projects to conduct Front-End Engineering Design (FEED) studies for carbon capture systems on coal and natural gas plants; the second was for four projects to receive up to $20 million each for cost-shared R&D under the Regional Initiative to Accelerate CCUS Deployment; and the third was for up to $35 million of cost-shared R&D under the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) program's Site Characterization and CO_2 Capture Assessment opportunity.

Key provisions of the 45Q credit are:
1) projects receive the tax incentive for a 12-year period once the facility is in service;
2) construction must commence by January 1, 2024[109]; and
3) there are minimum annual CO_2 capture requirements that vary by facility type.[n,110]

IRS guidance published in February 2020 identifies two options for 45Q applicants to meet the project commencement requirement: the physical work test and the five percent safe harbor. The physical work test requires work "of a significant nature" to be performed onsite (e.g., excavation, construction of the foundation, or installation of crucial elements) or offsite (e.g., the manufacture of specific parts and components), no matter their expense or effort. Some "preliminary activities" do not qualify as work "of a significant nature" and therefore do not contribute to a project qualifying for the tax credit (e.g. securing financing, exploring subsurface storage geology, obtaining permits and licenses, test drilling, and site preparation).[111]

Under the five percent safe harbor option, at least five percent of the total cost[o] must be incurred prior to the project commencement deadline, though if project costs ultimately exceed initial projections, the initial cost would not actually be five percent, thereby reducing or eliminating eligibility for the tax credit.[p] Independent of the option chosen to verify the construction commencement date, 45Q applicants must show continuous work or effort to advance towards completion of a qualified facility or carbon capture equipment to satisfy this requirement.

June 2020 proposed IRS guidance also specified that once the 45Q tax credit has been claimed on stored carbon, responsible financial parties must ensure that it remains securely stored for either five years after the tax credit was claimed or until the applicable monitoring requirements are complete, whichever is earlier; should the stored carbon escape, the responsible financial parties must return the tax credits they claimed.[112]

THE STRUCTURE OF THE STUDY

In sum, this comprehensive study of the potential for CCS to help California meet its deep decarbonization goals is framed by:

- The urgent need for action on climate change by California and around the globe. Because two thirds of the technologies that are needed to meet midcentury climate goals are either currently mature or in the early adoption stages of development, accelerating their use is essential for both near-term and longer-term climate targets.
- The support of California's leadership on climate policy and the size of its economy, both of which could have an outsized impact on the successful nationwide and global deployment of CCS technologies.
- The demonstrated value of California's NGCC fleet in providing the state's grid with firm power to ensure grid reliability as the state increases generation from variable renewables. The state's NGCC plants are well-suited for post-combustion retrofits with CCS technologies.
- The need for CCS to provide an emission reduction pathway for industrial subsectors that have extremely limited decarbonization options and, at the same time, hold high value for the state's economy.
- The need for an equitable and just transition to a zero emissions economy by ensuring equity issues are addressed when considering CCS infrastructure needs and buildout.
- Support for CCS deployment that could further enable a clean industry transition, providing key options for developing a hydrogen economy, CDR technologies, and new jobs to match the skillsets of conventional energy system workers.

n Eligibility thresholds are 500,000 tCO_2/yr for electricity generators; 100,000 tCO_2/yr for DAC facilities; 25,000 tCO_2/yr for other "beneficial use projects" (i.e. industrial pilot projects)

o This includes all costs properly included in the depreciable basis of a qualified facility or carbon capture equipment

p The 45Q guidance distinguishes between projects consisting of multiple carbon capture facilities and only one carbon capture facility. For example, if there are cost overruns for a project with multiple facilities, the project operator could claim the credit on a fraction of the facilities whose actual costs correspond to the initial five percent projection. No such leniency is granted to operators of a project consisting of a single facility, who are altogether ineligible under the five percent standard if final project costs exceed initial projections.

Subsequent chapters of this Action Plan for accelerating the development and deployment of CCS in California will examine in detail:

The Status of CCS in California. California has particularly strong financial incentives for CCS—namely eligibility under California's Low Carbon Fuel Standard—however, at present there are no operational large-scale projects and only a few projects in development.

The CCS Opportunity in California. Modeling the potential for CCS in California provides valuable information to inform business and policy actions. It also helps policymakers understand how investments can be made in a cost-effective manner. This section investigates the cost-effective CCS potential in California at the facility level. Additional system-level benefits and risks of CCS are identified for the power sector and for enabling CDR and hydrogen technologies.

Challenges to CCS Project Development in California. Informed by interviews with project developers, financiers, and innovators, and archival research and analysis of California's policy landscape, this section describes the barriers to widespread CCS deployment.

A Policy Action Plan for Maximizing the Value of CCS in California. The Action Plan integrates and builds on the opportunities and challenges to address multiple legal, policy and regulatory needs and requirements, at multiple levels (i.e. local, state and federal), to provide policymakers with policy options to successfully deploy CCS at scale.

Endnotes

1 "Ahead of Climate Week, Governor Newsom Announces Executive Action to Leverage State's $700 Billion Pension Investments, Transportation Systems and Purchasing Power to Strengthen Climate Resiliency." Office of Governor Gavin Newsom, September 20, 2019. Accessed September 15, 2020. https://www.gov.ca.gov/2019/09/20/ahead-of-climate-week-governor-newsom-announces-executive-action-to-leverage-states-700-billion-pension-investments-transportation-systems-and-purchasing-power-to-strengthen-climate-resili/

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Chapter 2

The Status of CCS in California

Over the last decade, California has enacted a number of policies that could pave the way for CCS to contribute to meeting the state's ambitious climate targets of a 40 percent reduction in GHG emissions by 2030[1] and carbon neutrality by 2045 with net-negative emissions thereafter.[2] In spite of these policy drivers, a number of factors have made it difficult for new CCS projects to move forward, and there are currently no operational large-scale CCS projects in California.[a]

KEY FINDINGS

- As of September 2020, there are five announced CCS projects that are in varying stages of planning and development in California.
- Every CCS project is unique from a planning and permitting perspective. The location and project type will impact what permits are necessary and which local, state, regional, and/or federal agencies would be involved.
- CCS projects that are co-located directly above suitable CO_2 storage have the benefit of not requiring CO_2 transport, which is the case for some of the proposed projects in California today.
- Because CCS projects involve at least two processes (capture and storage) and sometimes three (capture, transport, and storage), and can also cross numerous regulatory jurisdictions, permitting can be incredibly complex to navigate, understand, and undertake.
- At least three different agencies could be involved in industrial CCS at the outset of a project: the local air district for Clean Air Act (CAA) permitting, EPA Region 9 or the California Geologic Energy Management Division (CalGEM) for Underground Injection Control (UIC) well permitting, and another agency (typically a local agency) to serve as the "lead agency" for the California Environmental Quality Act (CEQA) process.
- CCS permitting for natural gas combined cycle (NGCC) power plants is less uncertain than permiting for industrial facilities because the California Energy Commission (CEC) has exclusive jurisdiction over NGCCs.
- While the adoption of the CCS Protocol under California's Low Carbon Fuel Standard (LCFS) was a clear step forward for the advancement of CCS deployment in California, a number of policy, legal, and financial challenges have limited its utilization. To date, no CCS projects have successfully applied for and received credits under the LCFS.
- California's current policy and regulatory environment makes it difficult for CCS to achieve its emission reduction potential in California. To help ensure that the state meets its near-term goals, maintains grid reliability with clean firm power, and supports its strong industrial base and the associated jobs, California's largest emitters need to begin developing CCS today.

a Note: There are several small-scale carbon capture and utilization (CCU) facilities operational in California that capture CO_2 for use in niche applications, rather than storing the CO_2 underground.

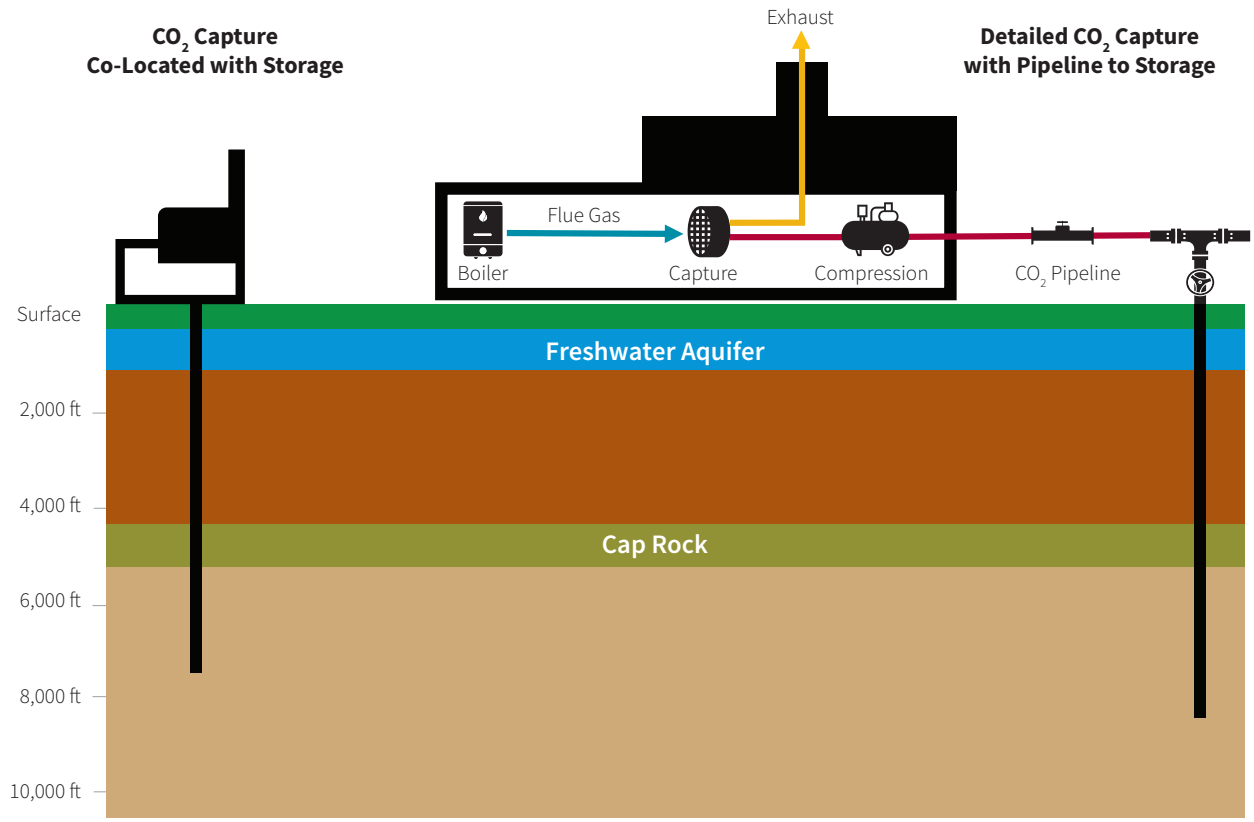
CCS is a set of relatively mature technologies that are primarily used to capture CO_2 from high emitting sources (i.e. power plants and industrial facilities) and permanently and safely store it underground. CCS is also one of the major approaches of carbon dioxide removal (CDR), using, for example, bioenergy with carbon capture and storage (BECCS) or direct air capture with carbon storage (DACCS). As noted in Chapter 1, CCS can provide significant emissions reductions for difficult to decarbonize sectors to help California achieve its deep decarbonization goals, while maintaining its strong industrial sector; ensuring a safe, affordable, and reliable power grid; and paving the way for future innovations in clean energy technology.

THE CCS VALUE CHAIN

CCS involves CO_2 capture; compression and transport to the storage site;[b] and subsurface injection via dedicated geologic storage or enhanced oil recovery (EOR). While there are many possible technology permutations of CCS, this study is largely focused on post-combustion amine absorption capture, with or without CO_2 pipeline transport, and permanent geologic storage in saline reservoirs. Figure 2-1 depicts the two major permutations of this process: CCS with and without CO_2 transportation. CCS projects that are co-located directly above suitable CO_2 storage have the benefit of not requiring CO_2 transport, which is the case for some of the proposed projects in California today.

FIGURE 2-1

SIMPLIFIED CCS VALUE CHAIN



There are two main permutations of CCS projects—those with on-site CO_2 storage and those that require CO_2 transportation from the emission source to the storage sink. *Source: Energy Futures Initiative and Stanford University, 2020.*

b CO_2 utilization is another potential application of captured carbon (e.g. feedstock for industrial commodities); however, that is outside the scope of this analysis.

CO_2 Capture

Carbon capture equipment is placed at or near the source of emissions, resulting in the separation of a highly purified stream of CO_2 from other waste gases across a range of industries, equipment, and processes. Table 2-1 illustrates many of the emitters, equipment, and processes that CCS technologies must be designed to accommodate, as well as the complicated environment in which both project developers and regulators will need to operate.

The capture of CO_2 can occur through three different methods: pre-combustion, post-combustion, and oxy-combustion. Pre-combustion capture is a process in which ambient air is drawn into an air separator that removes nitrogen from the gaseous mixture and outputs near-pure oxygen. Fuel (e.g., natural gas) is then gasified (rather than being combusted) in the presence of oxygen to produce a synthesis gas (syngas) composed primarily of hydrogen and carbon monoxide. After a resultant chemical reaction, the carbon monoxide is converted to CO_2 and enters an air capture device along with the hydrogen. Whereas the hydrogen is not captured and is ultimately used to produce electricity, the CO_2 is captured and enters a compressor where it is compressed into a supercritical state so it can be transported via pipeline for the purposes of utilization (e.g., EOR) or dedicated geologic storage. This method of CO_2 capture may be a less likely candidate for CCS retrofit projects due to its technical complexity.[3,4]

Oxy-combustion capture involves a similar process to pre-combustion capture, except the fuel is combusted with oxygen rather than gasified, which yields a flue gas of mostly water vapor and highly-concentrated CO_2.[5,6] During the initial oxygen separation stage, nitrogen is removed from the air and yields an oxygen purity of approximately 95 percent, which provides an environment that allows for CO_2 to be captured more easily after fuel combustion. Oxy-combustion capture has been considered a suitable technology for NGCC-CCS that could increase flexible operation in the electricity sector.[7] Despite its potential to simplify the CO_2 capture process, several challenges to oxy-combustion remain including operational, energy consumption, and capital costs.[8]

A variety of chemical and physical processes can be used for post-combustion capture, depending on the composition of the gas stream from which it is captured.

TABLE 2-1

EXAMPLES OF CO_2 SOURCES

Point Source of Emissions	Emitting Equipment	Emitting Processes
Power/electricity	Natural gas combustion turbine	CH_4 combustion
Petroleum refining	Fluidized catalytic cracking unit	Catalyst regeneration
Hydrogen production	Steam methane reformer	CH_4 reforming
Industrial cogeneration	Natural gas combustion turbine	CH_4 combustion
Cement production	Cement kiln	Limestone calcination & process combustion
Ethanol production	Fermentation tank	Fermentation
Fertilizer production	Steam methane reformer	CH_4 reforming
Biomass-derived H_2 production	Gas separation unit	Syngas hydrogen depletion

Carbon capture equipment can be utilized on a number of processes in multiple industries. *Source: Energy Futures Initiative and Stanford University, 2020.*

Some sources such as CO_2 from ethanol production, ammonia manufacturing, or hydrogen production from Steam Methane Reforming (SMR), require only dehydration and compression from carbon capture. Other sources, like power plants and cement manufacturing, have dilute concentrations of CO_2 (three to 30 percent) and require complex chemical separation processes. The most mature gas separation process is referred to as post-combustion capture using an absorption-based chemical scrubber that removes the CO_2 from the flue gas.[9]

Amine capture is the most mature post-combustion capture technology,[10] with higher efficiency and relatively lower costs than other capture technologies.[11] The process involves passing the captured gas stream through an amine solution, which selectively removes CO_2. Subsequent heating of the amine solution releases a concentrated stream of CO_2 that is captured then compressed into a supercritical state for transportation or storage.[12] Amine capture is easily scaled up and applied to large CO_2 point sources, such as power generation and hydrogen production, making it suitable "for the majority of industries that are anticipated to require CO_2 capture in the future."[13]

Two other less mature post-combustion carbon capture technologies are adsorption and membrane filtration. Adsorption technologies filter CO_2 from gas streams using materials that selectively adhere CO_2 to their surfaces. Membranes tend to be modular and cheap to produce, making them readily adaptable to several use cases. However, as membrane systems require relatively high pressures and concentrations of CO_2, they may not be suitable for deployment at large, dilute sources of emissions, such as power plants.[14]

Concerns have been raised that post-combustion capture retrofits may reduce the flexibility of NGCC plants to complement the intermittency of wind and solar generation. Recent analysis concludes, however, that "the integration of liquid-absorbent based post-combustion CO_2 capture has negligible impact on the power generation dynamics of the NGCC... [and] the decarbonization of an NGCC via post-combustion CO_2 capture does not appear to impose any limitation on the flexibility or operability of the underlying power plant in terms of power generation."[15]

Because this analysis is, in part, focused on meeting the state's near-term 2030 goals, it focuses on the more mature technologies. Additional and substantial CO_2 mitigation gains will likely be possible as other CCS technologies are developed and deployed; this should be reflected in policies to support CCS projects.

CO_2 Transport

CCS projects require transport of CO_2 from the capture facility to the storage site unless the emissions source is co-located (i.e. located directly above) with suitable CO_2 storage. Pipelines can efficiently move large amounts of CO_2 and most CCS projects in operation today rely on CO_2 pipelines for transport. CO_2 is compressed into its supercritical phase, which exhibits the properties of both a gas and a liquid. Compression of the supercritical fluid significantly reduces the transport volumes and enables efficient travel through pipes.[16]

The pipeline infrastructure needed to gather and transport CO_2 is significant and requires energy to maintain adequate pressures; new and specialized pipelines are needed as existing pipelines that transport other fluids are not designed to accommodate such high pressures. Also, dehydration processes may be required for CO_2 as it enters the pipeline to minimize or prevent pipeline corrosion.[17]

CO_2 Storage

Permanent geologic storage is a viable method to store captured CO_2 and prevent release of emissions into the atmosphere. Geological formations suitable for long-term CO_2 storage include saline reservoirs as well as depleted oil and gas fields.[18] When injected below a low-permeability geologic seal and away from faults, CO_2 can be permanently stored.[19] California has abundant suitable geologic storage sites, discussed in detail in Chapter 3.[20]

CO_2 can also be injected into an active oil or gas field to maintain subsurface pressure and increase oil mobility as a form of EOR. Most large-scale CCS projects to date have been driven by opportunities for CO_2 use in enhanced oil recovery (CO_2-EOR);[21] the focus of this study, however, will be on opportunities for permanent geologic storage options.

Finally, it is also possible to retrieve some fraction of the stored CO_2 if it becomes a valuable commodity at some point in the future, for example to create carbon-neutral aviation fuels from CO_2 and renewably-sourced hydrogen.

CALIFORNIA'S LOW CARBON FUEL STANDARD CREATES VALUE FOR CCS PROJECTS ALONGSIDE THE FEDERAL 45Q TAX CREDIT

Current financial incentives for CCS in California are the federal Section 45Q tax credit, described in Chapter 1, and California's LCFS.

AB-32 & the Low Carbon Fuel Standard

The enactment of the Global Warming Solutions Act of 2006, Assembly Bill (AB) 32, directed CARB to develop a plan to reduce statewide GHG emissions to 1990 levels by 2020. In 2009, CARB released its AB 32 Scoping Plan, establishing a framework for the creation of a suite of programs to decarbonize several sectors of California's economy. As part of its Scoping Plan mandate, CARB established the LCFS in 2009, and the regulation entered into force in 2011. The program's key goals are reducing GHG emissions from California's transportation sector by reducing the lifecycle carbon intensity (CI) of liquid fuels and by increasing the range of available transportation fuels in California to reduce petroleum dependency and improve air quality.[22] The LCFS is designed to reduce the CI of transportation fuels[c] by 20 percent relative to 2010 levels by 2030.[23]

The LCFS establishes a credit trading system designed to reduce the CI of fuel and enable economic efficiency and strategic flexibility for firms covered by the LCFS. Participation in the LCFS is mandatory for all petroleum fuel importers, refiners, and wholesalers in California, who must either lower the CI of the fuels sold to at or below the annual CI benchmark or purchase LCFS credits equal to the difference between their CI and the benchmark. Participation is optional for California low-CI fuel producers, who can generate credits (equal to the difference between their fuel CI and the benchmark CI).

As of September 2020, LCFS credits were trading for nearly \$200/tCO_2e, creating a significant incentive to use CCS to comply with the LCFS.[24]

CCS Protocol Under the LCFS

Following amendments to the LCFS made by CARB in 2018, a CCS Protocol was added to the program that enabled new and existing CCS projects to generate LCFS credits and participate in the credit market.[25] CCS projects can qualify for LCFS credits in two ways: through producing low-CI transportation fuel (known as "fuel pathway"); or as project-based credits through specific types of CCS projects. Eligible project categories include innovative crude, refinery investment credits, renewable hydrogen used in refining, and DAC projects.[26] Table 2-2 shows ways CCS projects can be eligible for LCFS credits under the expanded program.[27]

c A transportation fuel's CI is defined as the amount of GHG emissions occurring over the lifecycle of that fuel per unit of transportation energy delivered (in terms of gram CO_2e/megajoule).

The CCS Protocol requires projects to capture CO_2 and store it either in saline or depleted oil and gas reservoirs; or in oil and gas reservoirs used for EOR.[28] A CCS project's net GHG reduction is determined by subtracting the project's CO_2 emissions from the amount of CO_2 it injects (excluding recycled CO_2, in the case of CO_2-EOR).

$$GHG_{reduction} = CO2_{injected} - GHG_{project}$$

A project's GHG emissions ($GHG_{project}$) are defined as the sum of the GHG emissions from: carbon capture, dehydration, and compression; transport; injection operations; and direct land use change (each of these terms are also decomposed further; details can be found in the CCS Protocol).[29]

While the adoption of the CCS Protocol under the LCFS was a clear step forward for the advancement of CCS deployment in California, a number of policy, legal, and financial challenges have limited its utilization. While some CCS projects have either applied for or are contemplating earning LCFS credits (Box 2-1), none have successfully received credits under the LCFS.

TABLE 2-2

LCFS ELIGIBLE CCS PROJECT TYPES

	Direct Air Capture Projects	CCS at Oil and Gas Production Facilities	CCS at Refineries	All Other CCS Projects (e.g. CCS with Ethanol)
Location of CCS Project	Anywhere worldwide	Anywhere, provided transportation fuel is sold in California	Anywhere, provided transportation fuel is sold in California	Anywhere, provided transportation fuel is sold in California
Credit Method	Project-based	Project-based, under Innovative Crude Provision	Project-based, under Refinery Investment Credit Program	Project-based or fuel pathway
Earliest Date which Existing Projects Eligible	Any	2010	2016	Any
Additional Restrictions	None	Must achieve minimum CI or emission reduction	None	None

This table summarizes the categories and criteria under which CCS and DAC projects can qualify for the LCFS. *Source: Adapted from Global CCS Institute, 2019.*

Every CCS project is unique from a planning and permitting perspective. The location and project type will impact what permits are necessary and which local, state, regional, and/or federal agencies would be involved.

BOX 2-1

IN-DEVELOPMENT CCS PROJECTS PURSUING LCFS

As of October 2020, there are four CCS projects known to be actively submitting applications to receive LCFS credits once operational.

Clean Energy Systems

- Existing, mothballed biomass facility in California repurposed (i.e. brownfield development) with new technologies to produce hydrogen through gasification of biomass and capture of CO_2 from an oxy-fuel combustion process powered by hydrogen depleted synthesis gas
- Onsite geologic sequestration into saline storage via short pipeline, all of which is located within the property limits of the project
- Eligible for the LCFS under the Fuel Pathway method, as the hydrogen produced would serve California's transportation sector

California Resources Corporation

- Existing and operating NGCC used for combined heat and power (CHP) located within an oilfield in California paired with post-combustion carbon capture facility
- Captured CO_2 is transported onsite via pipeline to injection well(s) for EOR, and subsequently stored
- Project is eligible for LCFS credits through the project pathway, specifically the Innovative Crude provision

Interseqt LLC (White Energy and Oxy Low Carbon Ventures)

- Two existing ethanol plants in Texas which sell bioethanol into California for fuel blending, each paired with carbon capture equipment
- Captured CO_2 is sold to offtaker and transported via pipeline for non-co-located storage via CO_2-EOR
- Eligible for the LCFS under the Fuel Pathway method, as the bioethanol would serve California's transportation sector

1PointFive (Oxy Low Carbon Ventures and Rusheen Capital Management) and Carbon Engineering

- DAC facility located in Texas
- Captured CO_2 is injected for CO_2-EOR
- Eligible for the LCFS under the DAC project pathway

REGULATORY ENVIRONMENT FOR CCS IN CALIFORNIA

All infrastructure projects in California must meet permitting requirements at the local, regional, state, and federal levels, including environmental requirements with the goal of protecting public health, land, water, and air resources. California is notable for having its own environmental review process that is generally considered to be more stringent than the National Environmental Policy Act (NEPA) process called the California Environmental Quality Act (CEQA), which requires state or local government agencies to determine the environmental impacts of any proposed project. A key difference between CEQA and NEPA is that CEQA requires the identification of feasible measures for mitigating environmental impacts for projects to be approved. This policy has protected the state's natural lands and ensured critical public stakeholder input. In addition to the CEQA process, infrastructure projects must obtain various permits to ensure that the project would not have adverse environmental, water quality or air quality effects.

Every CCS project is unique from a planning and permitting perspective. The location and project type will impact what permits are necessary and which local, state, regional, and/or federal agencies would be involved. As noted, no two CCS projects are the same as they can take a number of permutations (i.e. with or without pipelines). A description of the fundamental permitting processes for CCS projects in California are described in Table 2-3. Of note, these are projects that do not require CO_2 transport and do not have project components in state or federal land or other sensitive habitats. This process is more representative of the types of projects under development in California today, in which the CO_2 source and sink are co-located, making the permitting process less complex.

TABLE 2-3

FUNDAMENTAL PERMITS AND PROCESSES REQUIRED FOR CCS PROJECTS IN CALIFORNIA AND RELEVANT REGULATORY AGENCY

Permit or Process Name	Program or Authority	Description	Agency of Jurisdiction (Industry)	Agency of Jurisdiction (Electricity)
Environmental Impact Report (EIR) **OR** Negative Declaration (ND)	California Environmental Quality Assessment (CEQA)	Under CEQA, which requires state and local agencies to identify the significant environmental impacts of a proposed project, a Lead Agency must prepare a detailed assessment of the project's potential environmental impacts if the project may have significant environmental impacts.[30] If the Initial Study shows there will not be a significant environmental impact, a **ND** may be issued. Otherwise, the Lead Agency must prepare an EIR that details the environmental impacts of such a project. The **EIR** is to be considered by all relevant state and local agencies in the permitting process of a given project.[31]	Situational[d,32]	CEC
Class VI well **OR** Class II well	EPA Underground Injection Control (UIC) Program	**Class VI** wells are used to inject CO_2 into deep rock formations for permanent geologic storage to reduce CO_2 emissions in the atmosphere and mitigate climate change. Class VI well requirements are designed to protect underground sources of drinking water and have requirements for siting, construction, operation, testing, closure, including well plugging and post-injection site care requirements for a default of 50 years after well closure.[33,34]	EPA Region 9	EPA Region 9; Potential coordination with CEC
		Class II wells are used to inject fluids into the ground for purposes of oil and gas production. There are several types of Class II wells including disposal, hydrocarbon, and enhanced recovery wells. Enhanced recovery wells are most utilized with CCS technology, in which CO_2 is injected into the ground for oil or gas retrieval. Similar to Class VI wells, Class II permits exist to protect underground drinking water.[35]	CalGEM	CalGEM; Potential coordination with CEC
Authority to Construct (ATC) **AND** Permit to Operate (PTO)	Clean Air Act (CAA)	If a stationary source of emissions is being constructed or undergoing major modification, it requires an **ATC** permit. California Air Districts or CEC issue the permits and monitor activity to ensure national, state, and local ambient air quality standards are achieved.[36] EPA Region 9 has delegated federal CAA permitting to the 35 air districts in California.	Local Air District	CEC
		When an **ATC** is issued, it is valid for one year. The intention of the permit is to be temporary, while the stationary source facility begins construction or modifications. If it expires before project completion, a renewal of the permit is required. When the project is completed, the Local Air District or CEC is contacted by the project developer to close the ATC. The ATC is replaced with a **PTO**, which is also to be renewed annually.[37] PTOs are required to meet CAA requirements.	Local Air District	CEC

This table details the fundamental permitting processes and applications required for all CCS projects in California as well as the regulatory agency/agencies that could be involved. *Source: Energy Futures Initiative and Stanford University, 2020.*

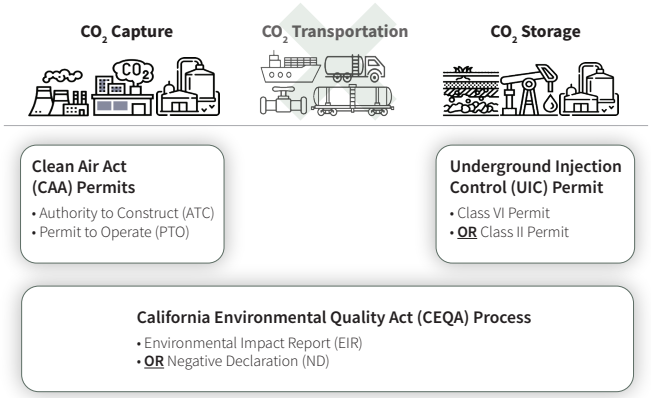
d The lead agency will normally be the agency with general governmental powers, such as a city or county, rather than an agency with a single or limited purpose (i.e. state agency). Lead agencies can also be a district that will provide a public service or public utility.

The fundamental regulatory permits and processes required for a simple and geographically contained CCS project (e.g. one with co-located capture and storage) are shown with the relevant part of the CCS value chain in Figure 2-2. As noted, thus far in California, in-development projects are those that do not require CO_2 transportation, which generally involves additional permitting and regulatory process steps. These projects are discussed further below.

In addition to the fundamental permitting processes described in Table 2-3 and Figure 2-2, there are a number of additional permits and/or assessments that may be required for a CCS project depending on the specific location and characteristics of the project. If federal permits are required, an applicant will most likely need to comply both with CEQA and NEPA. These permits and processes are overseen by a range of local, regional, state, and federal agencies. Additionally, projects seeking to receive LCFS credits under California's CCS Protocol must also complete the Permanence Certification process, which includes a number of requirements to ensure that injected CO_2 will remain underground for 100+ years after injection, as well as the LCFS pathway application and certification process to determine the amount of credits the project will receive. This is done through project-based crediting or fuel pathway crediting (described earlier). Figure 2-3 illustrates many of these project dependent permits and processes and the relevant part(s) of the CCS value chain. Table A-1 in Appendix A provides additional details.

FIGURE 2-2

SUMMARY OF FUNDAMENTAL APPLICATION PROCESSES AND RELEVANCE TO THE VALUE CHAIN FOR CCS PROJECTS IN CALIFORNIA



This figure shows the key permitting processes required for all CCS projects in California, which includes the ATC/PTO under the Clean Air Act, either a Class VI or Class II permit under the Safe Drinking Water Act UIC program, and either an EIR or ND under CEQA. *Source: Energy Futures Initiative and Stanford University, 2020.*

Permitting a CCS Project in the Electricity Sector

CCS permitting for NGCCs is less uncertain than permitting for industrial facilities because the CEC has exclusive jurisdiction over NGCCs. Following the national energy crisis of the early 1970s, the California state legislature passed the Warren-Alquist Act that created the CEC as the lead agency to oversee permitting and regulation of hermal power plants greater than 50 MW.[e,38]

Under the Warren-Alquist Act, the CEC must certify the plant and any "related facility or facilities"[39] that are "dedicated to and essential" to the operation of the thermal power plant.[40] Related facilities include pollution control systems that may include CO_2 capture.[41] CO_2 pipelines and/or CO_2 storage wells could fall into the category of related facilities if they are considered "dedicated to and essential to the operation of the thermal power plant."[42] Because no CCS project, including related CO_2 pipelines and storage wells, has ever received a permit from CEC, its jurisdictional reach remains unclear and it is possible that other agencies might have jurisdiction over components of a power sector CCS project.

The CEC's jurisdictional authority and permitting authority over CCS projects does not, however, extend to cases of multi-user pipelines and/or multi-user storage wells, since these shared infrastructures would no longer be considered "dedicated" to the power plant. In the case of the Hydrogen Energy California (HECA) project, CEC staff asserted in a scoping memo that it had jurisdiction over the capture facility and pipelines, until CO_2 reached a separate

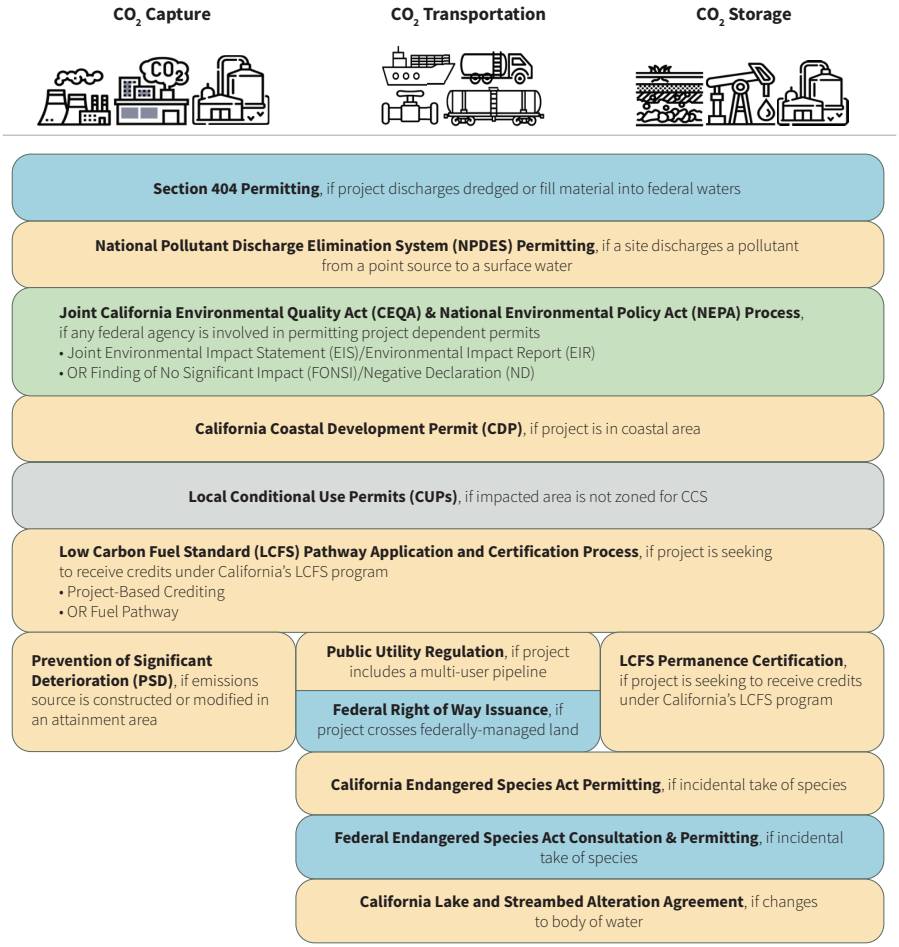
e The Act specifies that, "issuance of a certificate by the Commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency, or federal agency to the extent permitted by federal law."

entity's processing facility for EOR.[43] Once responsibility was transferred to the EOR processing facility, however, the activities were no longer "dedicated and essential to" the operation of the power plant, so the CEC no longer had exclusive jurisdiction. CEC staff also stated that it was unclear who would permit CO_2 storage as CalGEM [then the Department of Oil, Gas, and Geothermal Resources (DOGGR)] disclaimed any authority over regulation of permanent storage. Ultimately, the HECA project was discontinued before completion, so California does not yet have an example of an NGCC-CCS project over which CEC jurisdiction has been clarified.

The CEC's permitting process operates in place of requirements of other state and local requirements (i.e. CEQA, land use permitting, etc.); however, the CEC's jurisdiction does not supersede federal jurisdiction, so EPA Region 9 would still be the designated agency for Class VI permitting and, to the extent that a project triggers any of the project-dependent federal processes or permits summarized in Figure 2-3, the relevant federal agency would issue their own approvals and permits.

FIGURE 2-3

PROJECT DEPENDENT PERMITS AND AGENCY OF JURISDICTION FOR CCS IN CALIFORNIA



This figure shows additional permitting processes that could be required for various components of a CCS project depending on its exact location and potential impacts. These permitting processes fall under the jurisdiction of agencies at the local (grey), state (yellow), federal (blue), and joint state/federal (green) levels. *Source: Energy Futures Initiative and Stanford University, 2020.*

Permitting a CCS Project in the Industrial Sector

Permitting an industrial CCS project is more complicated as there is no CEC equivalent lead agency for CEQA and other state and local permits. At least three different agencies could be involved in industrial CCS at the outset of a project: the local air district for CAA permitting, EPA Region 9 or CalGEM for UIC injection well permitting, and another agency (typically a local agency) to serve as the "lead agency" for CEQA. Additionally, based on the analysis detailed in Chapter 3, of the 35 local air districts in California, there are seven[f] that contain CCS candidate facilities, and of the nine regional water districts, eight[g] contain some component of the CCS network (i.e. at least one industrial emission source, pipeline, and/or CO_2 sink).

Because CCS projects involve at least two processes (capture and storage), and sometimes three (capture, transport, and storage), and can also cross numerous regulatory jurisdictions, permitting can be incredibly complex to navigate, understand, and undertake. In interviews with project developers and financiers, permitting complexity and uncertainty was repeatedly noted as being a hurdle to CCS deployment in California. A discussion of the permitting challenges is further described in Chapter 4.

Figure 2-4 summarizes the fundamental project approvals needed and the overseeing agencies involved for either electricity or industry CCS projects. It also lists the LCFS processes that are required for any project seeking LCFS credits as well as some of the project

FIGURE 2-4

REGULATORY REQUIREMENTS AND AGENCIES OF JURISDICTION FOR ELECTRICITY AND INDUSTRIAL CCS PROJECTS IN CALIFORNIA

Agencies of Jurisdiction	Electricity	Industry	Agencies of Jurisdiction
CEC	Authority to Construct **and** Permit to Operate		Local Air District
EPA Region 9	Class VI permit **or** Class II permit		EPA Region 9
CEC, CALGEM			CALGEM
CEC	CEQA Process **or** Joint CEQA/NEPA Process		State/Local Lead Agency
CEC, Federal Lead Agency			Federal Lead Agency, State/ Local Lead Agency
CARB	LCFS Permanence Certification & Credit Generation Application		CARB

Project Dependent Permitting Requirements						
Coastal State Development Permits	**Federal land** Right of Way	**Federal Waters** 404, NPDES Permits	**Attainment Area** New Source Review: PSD	**CA Lake, Stream, River** Alteration Agreement	**Municipal Zones** Conditional Use Permits	**Endangered Species** State, Fed Permits

Core project approvals are shown in the center grey rectangles with the agencies of jurisdiction for industry (blue) and electricity (purple). The LCFS Permanence Certification and credit generation application are not regulatory permits but are required for all CCS projects seeking LCFS credits. Project-specific permitting processes are shown in dark grey. *Source: Energy Futures Initiative and Stanford University, 2020.*

f These local air districts are Shasta, SF Bay Area, San Joaquin Valley, Ventura, South Coast, Kern, and Mojave Desert

g District 1 was the only Water Quality District that did not have any component of the CCS network in it based on the analysis detailed in Chapter 3

dependent permitting requirements, which may or may not be required, depending on the exact location and specifications of the project. Additional description of project dependent permitting requirements is found in Appendix A.

CCS PROJECT DEVELOPMENT IN CALIFORNIA

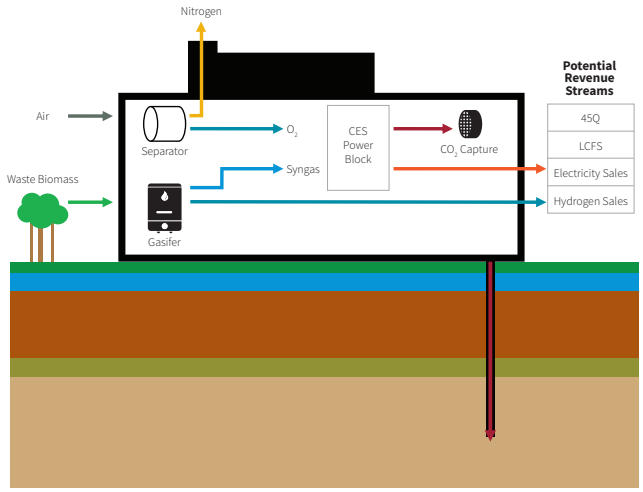
As of September 2020, there are five[h] announced CCS projects in varying stages of planning and development in California. An estimated annual total capture from four of these projects is approximately 2.5 $MtCO_2$ based on publicly available data.[i] While this is a small sample size, there are commonalities among these projects that may provide valuable insight for future projects. Each project is co-located with storage resources, eliminating the need to permit and build CO_2 pipeline infrastructure. Also, the two projects closest to commercial operation are designed to generate revenues in addition to those created by policy incentives. Finally, these two projects leverage existing infrastructure and brownfield facilities to manage total project costs.

The Sacramento-based Clean Energy Systems (CES) is developing a fleet of carbon-negative energy plants that use biomass waste from agriculture and forestry, using its proprietary oxy-combustion capture technology to produce hydrogen and electricity for use as low carbon transportation fuel.[44,45] CES intends to permanently store the CO_2 in co-located saline reservoir (eliminating the need for a CO_2 pipeline), and would be the first company to obtain a Class VI permit in California. A simplified diagram of the CES project is shown in Figure 2-5.[46]

This brownfield project repurposes existing, mothballed biomass facilities that exist on industrial zoned lands, thereby lowering (on a relative basis compared to new/greenfield) capital costs. The project design would support the operation of the CES plant as a poly-generation facility, producing electricity and/or hydrogen for sale, depending on prevailing market and contractual prices. Revenue

FIGURE 2-5

CLEAN ENERGY SYSTEMS CCS PROCESS AND REVENUE STREAMS



Clean Energy Systems intends to deploy carbon capture at its biomass to hydrogen and/or electricity facility and inject the CO_2 onsite for permanent geologic storage. *Source: Energy Futures Initiative and Stanford University, 2020. Using data from Clean Energy Systems, 2020.*

diversity is a key resource of the CES business model as an approach to ameliorate economic variability. Operational decisions are affected by the number of LCFS credits generated per revenue stream.

The California Resources Corporation (CRC) in Bakersfield, California is planning a CCS project that will capture CO_2 from its 550 MW NGCC power plant co-located with the Elk Hills oil field, where it would utilize the CO_2 for EOR. This project benefits from CRC's ownership of a large expanse of land surrounding its CO_2 injection wells, leaving the company less vulnerable to potential liability and pore space uncertainty issues.[47] A simplified diagram of CRC's CCS process is shown in Figure 2-6.

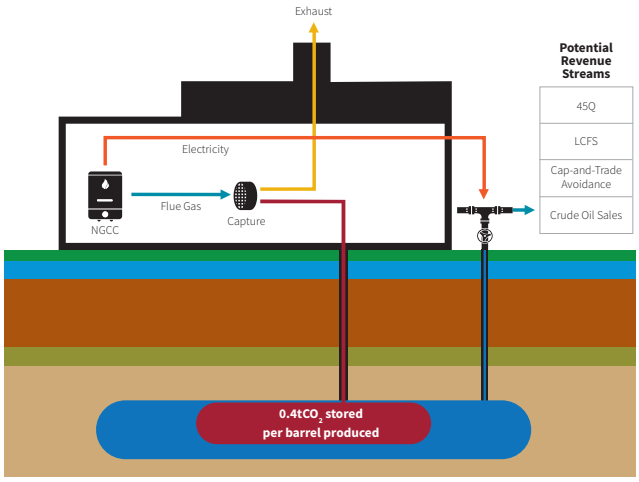
This brownfield project would receive LCFS credits only on the portion of CO_2 captured that can be allocated to electricity produced for oil field operations, in line with the

h This includes Clean Energy Systems (CES) biomass to hydrogen with permanent geologic storage; California Resources Corporation (CRC) NGCC capture used for EOR; DTE Energy's transport and storage hub concept; Chevron's NGCC capture pilot, and a carbon capture pilot on the Los Medanos NGCC owned by Calpine Corporation. Note: only the CRC project is included in the Global CCS Institute CO_2RE Database utilized in Chapter 1 to profile Global and US CCS development.

i Note: The Chevron NGCC capture pilot does not include estimated or goal capture amount.

FIGURE 2-6

CALIFORNIA RESOURCES CORPORATION CCS PROCESS AND REVENUE STREAMS



California Resources Corporation (CRC) intends to deploy carbon capture on its NGCC power plant and inject the CO_2 for EOR onsite at the Elk Hills oil field. *Source: Energy Futures Initiative and Stanford University, 2020. Using data from California Resources Corporation, 2020.*

rules of the LCFS Innovative Crude pathway. Other revenue streams include the 45Q federal credit and proceeds from produced and sold oil from EOR operations. Like the CES project, the CRC project contemplates multiple revenue streams, and uses existing infrastructure at its co-located source and sink to minimize capital costs.

There are also two carbon capture pilot projects in California that received DOE funding in September 2020; it is not clear, however, if these projects will inject the CO_2 for geologic storage. The first is a project by Chevron that will capture flue gas using a novel post-combustion capture technology at an oil field operating under realistic conditions. The second is a carbon capture demonstration project at the Los Medanos NGCC owned by Calpine Corporation that will capture 10 tCO_2/day. This project is designed to increase understanding of impacts of carbon capture on the functioning of a commercially dispatched NGCC.[48]

Finally, DTE Energy is pursuing a regional network of carbon transport and storage facilities to serve industrial emitters in the San Francisco Bay, Central Valley, and Los Angeles areas. This model would utilize permanent CO_2 storage in saline formations or depleted oil and gas fields and has the goal of storing one $MtCO_2$/yr or more per storage facility.[49]

AN UNCERTAIN FUTURE FOR CCS IN CALIFORNIA

As noted in Chapter 1, previous EFI analysis concluded that without CCS, it would be very difficult for California to meet its 2030 emissions reduction targets. EFI's 2019 study also found that CCS was the largest source of potential 2030 emissions reductions in both the power and industry sectors.

California's current policy and regulatory environment makes it difficult for CCS to achieve its emission reduction potential in California. To help ensure that the state meets its near-term goals, maintains grid reliability with clean firm power, and supports its strong industrial base and the associated jobs, California's largest emitters need to begin developing CCS today.

A range of actions are needed to take advantage of emissions-reduction opportunities associated with CCS in both the industrial and power sectors: planning, permitting, and building individual CCS projects and supporting infrastructure will take years of dedicated effort.

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Chapter 3

The CCS Opportunity in California

This chapter investigates the CCS potential in California at the facility level, including its costs and cost-effectiveness. Additional system-level benefits and risks of CCS are identified for the electricity sector and for enabling carbon dioxide removal (CDR) technologies. Much of the analysis in this chapter is modeling-based, providing valuable information to inform industry and policymakers as they consider deep decarbonization options and pathways.

KEY FINDINGS

- California has one of the largest geologic storage potentials in the United States, with over 70 gigatons (Gt) of CO_2 storage potential, the majority of which is located in the Central Valley.
- There are 76 existing electricity and industrial facilities [25 natural gas combined cycle (NGCC) facilities and 51 industrial sites] identified by this analysis to be candidates for CCS retrofit in California. These facilities emit 59 million metric tons of carbon dioxide per year ($MtCO_2$/yr).
- Facilities that are co-located directly above a potential storage resource account for up to 5.6 $MtCO_2$/yr of emissions. Another 4.1 $MtCO_2$/yr of emission sources are within 10 miles of suitable CO_2 storage, and would require relatively minimal infrastructure development.
- There are 34 facilities that generate positive modeled revenue with CCS retrofits and could abate 21.5 $MtCO_2$/yr.
- NGCC power plants have higher capture costs relative to other emissions sources and are generally not eligible for the Low Carbon Fuel Standard (LCFS). However, adding NGCCs with CCS retrofit to a renewables-dominated grid is a cost-effective way for California to meet its SB100 objectives. Adding NGCC-CCS lowers overall system costs by avoiding the need to overbuild renewable generation and energy storage to meet reliability requirements. Adding some NGCC-CCS also has the benefit of reducing land use requirements for renewable generation.
- Roughly 50 MtCO2/yr of capturable emissions require development of up to 1,150 miles of new pipeline, connecting emission sources with suitable geologic storage. Although pipelines have relatively low capital and installation costs, permitting and building a new CO_2 pipelines in California is perceived to be a formidable task.
- There are potential CCS hubs in the Los Angeles and San Francisco Bay areas, which could result in emission reductions of 25.2 $MtCO_2$/yr and 14 $MtCO_2$/yr, respectively. Hubs offer 'economy of effort,' where Front-End Engineering Design (FEED) studies, permitting, and construction could be economized due to co-location of emission sources. Project returns may also be enhanced with centralized storage facilities, managing flows from multiple sources.
- While the primary objective of CCS is to reduce CO_2 emissions and mitigate climate change, post-combustion capture can also result in the reduction of criteria air pollutant emissions from certain facilities.
- Some of the emission sources suitable for CCS retrofit, new pipeline infrastructure, and CO_2 storage sink locations would likely be located in or adjacent to communities with high poverty and high unemployment. CCS projects can provide both economic and health benefits for these disadvantaged communities.
- Examined project examples point to attractive investor internal rates of return (IRR) for carbon capture on ethanol with co-located storage and a refinery capture hub with offsite geologic storage. This is in sharp contrast to CCS on NGCC facilities, which under current market and policy regimes, are modeled to be uneconomic.
- Development of CCS infrastructure can also enable emergence of new industries, such as hydrogen production and negative-emissions carbon dioxide removal (CDR) [direct air capture (DAC) and bioenergy with CCS (BECCS)]. Both technologies will rely on geologic storage. CO_2 storage is likely to be a critical technology for supporting development of a power-to-fuel industry, where interim storage of both hydrogen and CO_2 feedstocks will be needed.

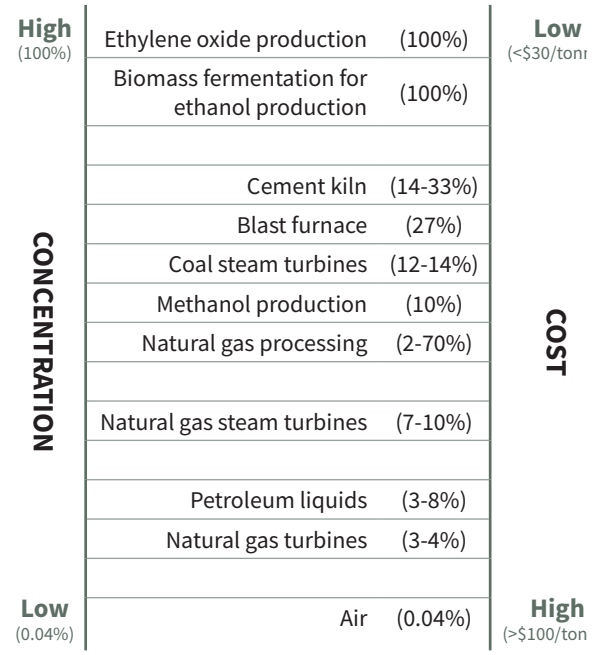
As noted in Chapter 1, electricity and industry are the second and third largest emitting sectors in California, respectively contributing 14.7 and 21.1 percent of the state's total emissions. Decarbonizing California's electricity sector will be particularly important in reaching economywide GHG emission reductions due to California's policies for the electrification of the transportation and buildings sectors. Ensuring that the zero-carbon grid by 2045 required under SB100 is both reliable and affordable is also critical.

The industrial sector in California is a major emitter contributing roughly 100 $MtCO_2e$ of emissions per year since 2000. Decreasing emissions from the industrial sector will therefore need to become a major focus of mitigation efforts in California over the next two decades to meet its climate goals.

To assess the potential role of CCS in contributing deep emissions reductions in support of the state's ambitious climate goals, this analysis conducted a bottom up assessment of stationary emission sources in California's electricity and industry sectors to identify CO_2 capture potential and modeled the value of CCS in the power sector given the state's SB100 2045 target. This study also conducted analysis to determine an estimate of the CO_2 storage potential in the California. These analyses were used to identify the CCS infrastructure and project development opportunities in California as well as the potential future industries enabled from CCS.

FIGURE 3-1

CONCENTRATIONS AND COSTS OF CARBON CAPTURE



This figure shows the percentage of CO_2 in different sources of CO_2. High purity sources of CO_2 have low capture costs, and the lower the percent of CO_2 in the source, the high the capture cost. Capturing CO_2 from air, or direct air capture (DAC), has the highest capture cost. *Source: Energy Futures Initiative and Stanford University, 2020*

ANALYSIS OF EMISSIONS ABATEMENT OPPORTUNITIES FROM CCS IN CALIFORNIA

As described in detail in Chapter 2, the first step in the CCS process involves the capture of CO_2, which can occur through different methods, depending on the purity of the CO_2 stream, the nature of the process producing the CO_2, and capture technology choices by the project operator. In general, the higher the purity of a CO_2 source, the lower the costs per ton of CO_2 captured (Figure 3-1). For dilute sources of CO_2, this analysis focuses on post-combustion amine absorption systems, which are currently the most commercially deployed technologies due to their higher efficiency and lower cost. Also, as noted earlier, retrofitting existing facilities with post-combustion capture greatly reduces the capital cost of deployment of CCS.

With its large geologic storage potential,[1] and strict emission reduction targets, California could be well positioned to achieve deep and sustained emissions reductions from CCS in the electricity and industrial sectors. This analysis has identified 25 NGCC sites and 51 industrial facilities across five subsectors with combined capture potential of nearly 60 $MtCO_2$ that could be attractive candidates for CCS retrofit projects in California. Box 3-1 outlines key features of the evaluation framework used to identify sites that are most suitable for electricity and industrial CCS.

BOX 3-1

EVALUATION FRAMEWORK FOR IDENTIFYING CANDIDATES FOR CO_2 CAPTURE

Evaluation criteria were developed to highlight sources of emissions that may provide lower barriers for CCS deployment in the near-term. For both the electricity and industrial sectors, a two-step approach was taken. First, emission sources were assessed for their technical and economic suitability for CO_2 capture. Second, facilities were further analyzed based on their emissions profile as well as facility type (for electricity) or subsector (for industry). The specific data sources and methodologies utilized to identify near-term CCS opportunities in the electricity and industrial sectors are described below.

Electricity Sector

Power plant size, age, and 2018 operational data were obtained from the Hitachi ABB Velocity Suite database. Combined heat and power (CHP) plants identified in Subpart D of EPA's GHG Reporting program were included in this analysis. The following criteria were utilized to highlight candidate sites that would provide lower barriers for CCS deployment in the near-term: (1) NGCC units only; (2) built after 2000; (3) no planned retirement; and (4) unit size greater than 250 MW. NGCC units larger than 250 MW emitted an average of 770,000 tCO_2 per unit in 2018, which is approximately the size of the smallest commercial-scale CCS project currently operating in the U.S.

Twenty-five NGCC power plants met these criteria and were identified as opportunities for deploying CCS in the power sector in the near-term. The cost of retrofitting a NGCC plant largely consists of capital costs for hardware, operational and maintenance costs, and financing costs. The capture cost at each prospective facility was assessed and scaled to the size of the power plant undergoing retrofit. The analysis calculated weighted-average values for capture costs and economic subsidies for NGCC retrofit sites.

Industrial Sector

This analysis used subsector-specific capture costs derived from the literature and cross-checked those costs on common factors for energy costs, capital costs, and inflation and calculated weighted-average values for capture costs.

Using EPA's Facility Level Information on GHG Tool (FLIGHT) data set, any facility that did not register an emissions level in 2018 was excluded from consideration. Additional filters were used to eliminate any facilities that were listed under industrial subsectors that are not suitable for CO_2 capture (e.g., Waste)[a] and those that did not register an emissions level of ≥100,000 tCO_2, the level necessary to meet the minimum annual capture requirement required for 45Q eligibility.

The CHP plants included in this analysis were those that reported under EPA GHG Reporting Program (GHGRP) subpart C for general stationary fuel combustion sources. For ease of retrieving data for the CHP plants, this analysis used 2018 data from the EPA Emissions and Generation Resource Integrated Database (eGRID). EPA GHGRP classifies ethanol as a "miscellaneous combustion source;" the ethanol plants included in this analysis are those that reported under EPA GHGRP subpart C for general stationary fuel combustion sources.[b]

To better understand the opportunities for CCS at petroleum refineries, this analysis used the detailed facility-level emissions reports available through FLIGHT. Some of the individual emission sources detailed in FLIGHT lend themselves readily to the possibility of CCS, which ultimately led to the selection of many petroleum refineries as ideal candidates. Owing to high retail electricity prices in California, many refineries opt to operate electricity generation or CHP units in or near a refinery; these units are responsible for very high emissions levels in California, rendering them highly suitable for CCS. Many refining processes also rely on large amounts of hydrogen, the onsite production of which also generates CO_2 at the megaton-scale. Where possible, this analysis separated the emissions stemming from hydrogen and CHP plants located at petroleum refineries. Finally, the machinery involved in the refining process itself, often identified in FLIGHT reports as fluid catalytic cracking units (FCCUs), can generate hundreds of thousands of tCO_2 per year at a single unit. Altogether, these factors led to the selection of various petroleum refineries as prime candidates for CCS to help reach California's emissions reductions goals.

a Industrial subsectors that were not included were as follows: Power Plants; Fluorinated Chemicals; Waste; Petroleum & Natural Gas Systems—Direct Emissions; Electrical Equipment; Electronics Manufacturing; Mining; Carbon Dioxide Supply and Injection; Petroleum Products; Natural Gas and NGL Suppliers; Industrial Gas Suppliers.

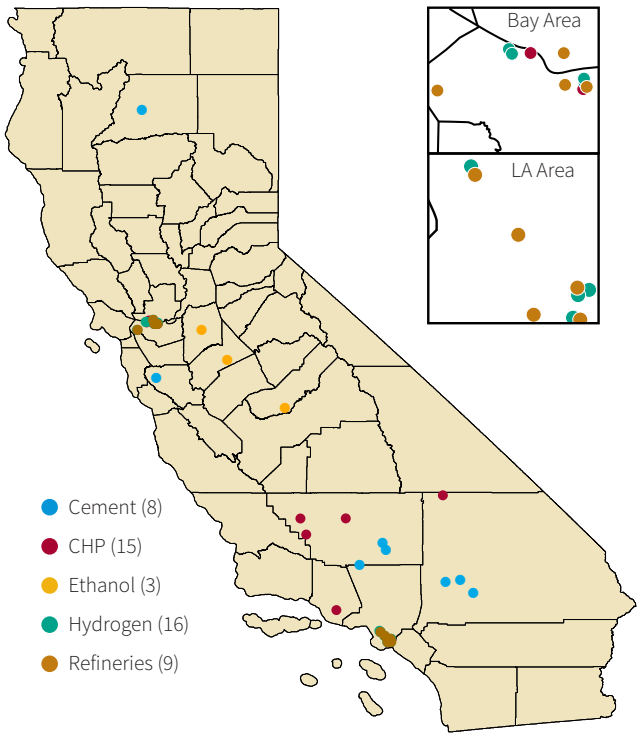
b All covered entities that reported to the EPA GHGRP for reporting year 2018 were downloaded from FLIGHT using the following filters: Data Year (2018); Data Type (All Emitters); Browse to a State (all states); Emissions by Fuel Type (all fuel types); Filter by Status (All Facilities). This search returned 9,641 facilities. The data was then filtered on the 'STATE' variable for 'CA' which returned 596 facilities.

CO_2 Capture Opportunities in the Industrial Sector

The 51 candidate industrial facilities for CCS had emissions of around 36 $MtCO_2$ in 2018, of which the capturable emissions were estimated to be 31.8 $MtCO_2$. The potential level of avoided emissions is associated with 16 hydrogen plants, 15 CHP plants, nine petroleum refineries (FCCUs)[c], eight cement plants, and three ethanol plants (Figure 3-2). The candidate facilities are grouped by industrial subsector and detailed by aggregate emissions level (Figure 3-3 and Table 3-1).

FIGURE 3-2

CO_2 CAPTURE OPPORTUNITIES IN THE INDUSTRIAL SECTOR



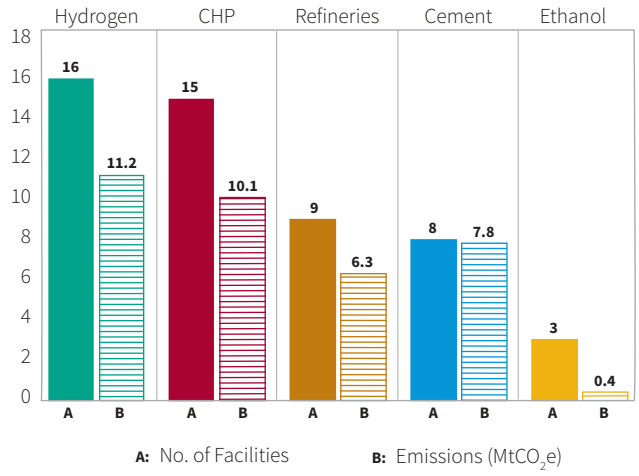
This analysis identified 51 industrial facilities across five subsectors that are candidates for CCS retrofit in California. Note: Upper inset map is the San Francisco Bay Area. Lower inset map is the Los Angeles area. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from U.S. EPA, 2020.*

Hydrogen Production: All 16 hydrogen facilities are either co-located with petroleum refineries or are over-the-fence merchant plants that supply the refineries with hydrogen. Hydrogen plants have the highest industrial aggregate emissions level by subsector at nearly 11.2 $MtCO_2$ and are primarily located in the San Francisco Bay Area and Los Angeles Area (coincident with the location of petroleum refineries).

Combined Heat and Power: The 15 candidate CHP plants have the second highest aggregate emissions level by subsector of the candidate industrial facilities at nearly 10.1 $MtCO_2$. The CHP facilities are primarily located in the San Francisco Bay Area and Los Angeles Area (coincident with the location of petroleum refineries) and in the southern portion of the Central Valley (associated with the production of heavy crude oil). These plants tend to operate on a steady and predictable schedule and are not dependent on California Independent System Operator (CAISO) dispatch as NGCCs are, which could make them especially attractive candidates for CCS.

FIGURE 3-3

INDUSTRIAL FACILITIES IDENTIFIED FOR CCS RETROFIT



This analysis found 51 industrial CCS candidate facilities with a combined emissions level of 36 MtCO2. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from U.S. EPA, 2020 and using methodology from NPC, 2019.*

c Analysis includes refineries operational with no plans for closure or conversion as of May 2020.

TABLE 3-1

SOURCES OF EMISSIONS, POTENTIAL CAPTURABLE EMISSIONS, COSTS, AND INCENTIVE ELIGIBILITY

Metric	NGCC	Hydrogen	CHP	Refining	Cement	Ethanol
Number of Facilities	25	16	15	9	8	3
Total Emissions, 2018 ($MtCO_2e$)	21.6	11.2	10.1	6.3	7.8	.43
Assigned Capture Rate	90%	90%	90%	90%	90%	100%
Total Capturable Avoided Emissions ($MtCO_2$)	27.5	10.1	9.1	5.2	7.0	.43
Weighted Average Capturable Emissions (tCO_2 per facility per year)	1,100,000	630,000	600,000	575,000	880,000	142,000
Estimated Capture Cost Range ($/$tCO_2$)	$62 -$96	$58-$101	$60-$131	$58 -$73	$48 - $75	$20 - $23
LCFS Eligibility	No*	Yes**	Yes***	Yes**	No	Yes

Notes:
* Elk Hills Power is considered 40% LCFS eligible as some of the electricity will be used for oil field operations
**Hydrogen and Refining were considered 80% LCFS eligible as some refined product is exported out of state.
*** CHPs associated with refining operations were considered 60% LCFS eligible due to rationale in ** yet reduced another 20% because some power generated by CHPs is sold to the grid. CHPs associated with upstream oil and gas production activities were considered to be 50% LCFS eligible.

This table provides key details, assumptions, and capture costs for the 76 facilities deemed eligible for CCS retrofit based on this analysis.
Source: Energy Futures Initiative and Stanford University, 2020.

CHP plants are eligible for LCFS under the Refinery Investment Credit Program[2] if they meet certain conditions. The first condition is that the CHP plant must supply electricity or steam directly to the petroleum refinery (behind-the-meter) and must be located within the boundaries[d] of the refinery. Note that the CHP plants can be owned by a third party. The second condition is that the captured CO_2 must be stored in a manner that adheres to the requirements of the LCFS CCS Protocol. Note that the credit will be pro-rated if 100 percent of the electricity or steam does not go to the petroleum refinery.[3]

Cement Production: Eight cement plants met the criteria for CCS retrofit. Cement plants have the third highest aggregate emissions level by subsector of the candidate facilities at roughly 7.8 $MtCO_2$. These plants could be especially attractive candidates for industrial CCS due to their relatively low capture costs, capture eligibility at only two primary individual emissions sources (precalciner and kiln)[4], and the ability to capture process emissions from the calcination of limestone which constitutes the majority (roughly 60 percent) of the total CO_2 emission in California's cement subsector.[5]

Petroleum Refining: Nine petroleum refineries met the criteria for CCS retrofit. Petroleum refineries have the fourth highest aggregate emissions level by subsector of the candidate facilities at nearly 6.3 $MtCO_2$. They are all located in the San Francisco Bay Area and Los Angeles Area where they serve the large population centers. In general, petroleum refineries are characterized by a relatively high degree of systems integration and a patchwork of individual emissions sources per facility,[6] and frequently have hydrogen and CHP plants associated with their

d Within the boundary means that the equipment specified in the project and refinery are in actual physical contact, which is defined as located on one or more contiguous or adjacent properties (may also be separated by a public roadway or public right-of-way).

operations. This analysis focused on capturable emissions from spent catalyst regenerators at FCCUs (essentially petroleum coke boilers).[7]

Despite the relatively rapid growth of the zero-emission vehicles (ZEV) market in California,[8] the establishment of a formal ZEV program,[9] and Governor Newsom's recent executive order on ZEVs,[10] the state will still have a sizeable stock of internal combustion engine vehicles on the road beyond 2030. In December 2019, the state reported 36.5 million vehicles on its roadways across a range of vehicle classes,[11] of which the forecasts for the light-duty vehicle fleet and ZEVs both show a considerable stock increase to 2030.[12] A continued reliance on petroleum products for heavy-duty transport, shipping, and aviation, for which there are currently very limited technology options, suggests that CCS could provide an important mitigation opportunity for petroleum refineries until there is a greater penetration of ZEVs and further technological advancement (e.g., commercial aviation electrification) across the transportation sector. There is also an issue with tourism and other interstate commerce that could be limited by California policy on ZEVs.

Ethanol Production: Three ethanol plants met the criteria in for CCS retrofit. Ethanol plants had the lowest aggregate emissions level by subsector of the candidate facilities at nearly 0.4 $MtCO_2$ and are all located in the Central Valley. These plants are characterized by high-purity streams of CO_2 and low capture costs, which make them especially attractive candidates for industrial CCS. Previous estimates have suggested that biorefineries with CCS could supply California with 1.5 billion gallons of ethanol per year and meet four to five percent of the state's 2030 emissions reduction goal at low cost.[13]

CO_2 Capture Opportunities in the Electricity Sector: Meeting SB100 goals

One of the most critical policies for meeting California's climate goals is a clean electricity system.[14] California's electricity sector currently has one of the lowest emissions intensities in the U.S.[15] because of its lack of coal-fired generation, relatively high penetration of renewables, substantial hydroelectric generation, and generally newer and more efficient natural gas generating fleet. Decarbonizing California's transportation sector and some parts of the industrial, residential, and commercial sectors relies heavily on electrification and the concurrent decarbonization of the electricity grid.

As noted, in 2018, California passed SB100, which increased the state's renewable portfolio standard (RPS) goal from 50 percent to 60 percent by December 31, 2030. SB 100 also mandated a net-zero carbon electricity grid by December 31, 2045, where 100 percent of retail power sales would be eligible renewable and zero-carbon resources.[16] While eligibility for compliance has yet to be defined for the SB100 mandate, it may include large-scale hydro, hydrogen, nuclear, or NGCC with carbon capture and storage (NGCC-CCS).[17] Also unclear is whether offsets through negative emission strategies will be considered (e.g. BECCS). An analysis of California's pathways for achieving its SB100 goals[18] indicates that in all scenarios, renewable resources will be both critical and continue to expand through 2045 and, at the same time, will need approximately 30 gigawatts (GW) of clean firm generation resources[e] to cost-effectively decarbonize its grid.[19] In January 2021, the CEC, CARB, and the CPUC are scheduled to release the Joint Agency Report required by SB100; draft results exclude NGCC-CCS. This is discussed in greater detail in Chapter 4.

Decarbonizing the grid by developing only battery storage and intermittent renewable resources, however, results in a system that must be drastically overbuilt to maintain some level of reliability; at the same time it raises questions about the storage duration of existing battery technologies. The result: extensive land use, underutilization of some resources, and a system that is significantly more expensive and potentially less reliable than a system with clean firm resources.

Clean firm resources complement a high share of intermittent renewable resources and can reduce the need for overbuilding the electricity system and drastically reduce the cost of decarbonization. California currently has about six GW of clean firm resources, including nuclear,

e The U.S. EIA defines firm power as "power or power-producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions." Clean firm generation includes firm power resources that are low- or zero-emissions, including nuclear, geothermal, biomass, hydro, NGCC-CCS, hydrogen, and other carbon free fuels using net-zero processes.

geothermal, and biomass power, which is responsible for approximately 16 percent of total system generation in 2018. California is planning, however, to retire its only remaining nuclear power plant (Diablo Canyon, which is a 2,256 MW nuclear power plant that is responsible for about nine percent of California's in-state electricity production) by 2026.[20] Further expansion of nuclear power is limited by California's moratorium on new nuclear generating capacity absent a permanent solution to waste disposal.[21] Also, California has existing biomass and geothermal capacity but its expansion is limited by in-state resource availability.[22] Absent technology breakthroughs, including the timely process of widespread market diffusion, California will need to expand its clean firm capacity by 2045 and given the limited range of resources that can contribute to clean firm capacity, it will be critical to maintain optionality for their use and deployment.

Clean firm resources complement a high share of intermittent renewable resources and can reduce the need for overbuilding the electricity system and drastically reduce the cost of decarbonization.

In this regard, there are an estimated 195 utility-scale gas-fired units that generate electricity in California (NGCCs, combustion turbines, and steam turbines), in 101 different locations.[23] Forty-eight of these units are NGCCs, which consist of gas and steam turbines. The waste heat from the gas turbines is utilized by steam turbines to generate additional energy. NGCCs are often larger than simple cycle gas combustion or steam turbines in nameplate capacity and are also 34-45 percent more efficient.[24] NGCCs represent the majority of newly added gas-fired capacity built in California and have high utilization rates (Figure 3-4). Conversely, natural gas combustion turbines, which are less efficient, are utilized primarily as peaker plants within California's electricity system, resulting in lower average capacity factors.

NGCC power plants are the most suitable for post-combustion carbon capture retrofits. NGCCs have readily available steam that can be utilized for solvent regeneration and also have sufficient generator size for cost-effective economies of scale for retrofit.

The 25 NGCC power plants that meet the criteria (Box 3-1) for near-term retrofit (Figure 3-5) accounted for 21.6 of the 28.5 $MtCO_2$ emissions from all gas plants in 2018 and have a total of 14 GW of generation capacity (Table 3-1). If retrofitted with a post-combustion system with 90 percent capture, and assuming a 60 percent capacity factor (not necessarily what they are running at today),[f] there is a total annual capture potential of 27.5 $MtCO_2$ (11 percent of the 2030 economywide emissions reduction target). The capture cost at each prospective facility was assessed and scaled to the size of the power plant undergoing retrofit. All power plants that meet the criteria for near-term retrofit have emissions ≥100,000 tCO_2, which is the level necessary to meet the minimum annual capture requirement required for 45Q eligibility. The resulting costs of retrofit for the identified NGCC power plants range from \$62/tCO_2 to \$96/tCO_2, with an emissions weighted average of \$76/tCO_2.

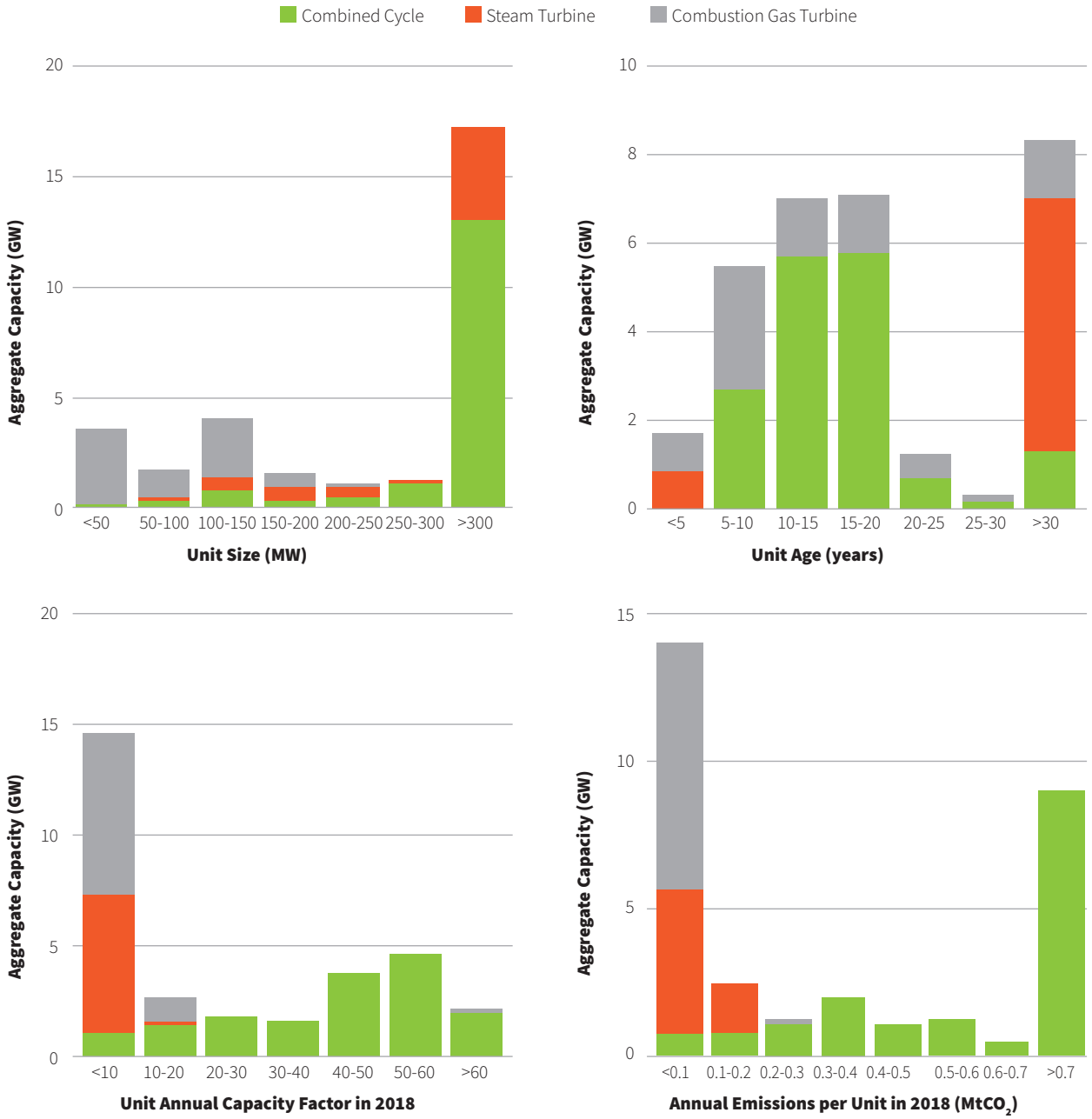
Value of CCS in the Electricity Sector in the Near-Term

A 2018 CEC analysis found that the electricity sector must reduce its emissions by 32 $MtCO_2$ in 2030 to meet the state's SB32 economywide emissions reduction goal.[25] This study utilized a capacity expansion and dispatch model for the California grid to assess what role CCS might play in meeting California's 2030 SB100 and SB32 goals within the electricity sector. The model finds the lowest cost combination of new technology buildout and their respective operating schedules to simultaneously meet electricity demand and policy goals. Details of this model are provided in Appendix B, along with costs and other related assumptions.

f Capacity factor determined based on power sector modeling analysis that is described in the next section.

FIGURE 3-4

CHARACTERISTICS OF GAS POWER UNITS IN CALIFORNIA, 2018



NGCCs are often larger in nameplate capacity due to their additional energy output and dominate the majority of new gas-fired capacity built in California. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Hitachi ABB Velocity Suite and EPA eGRID database.*

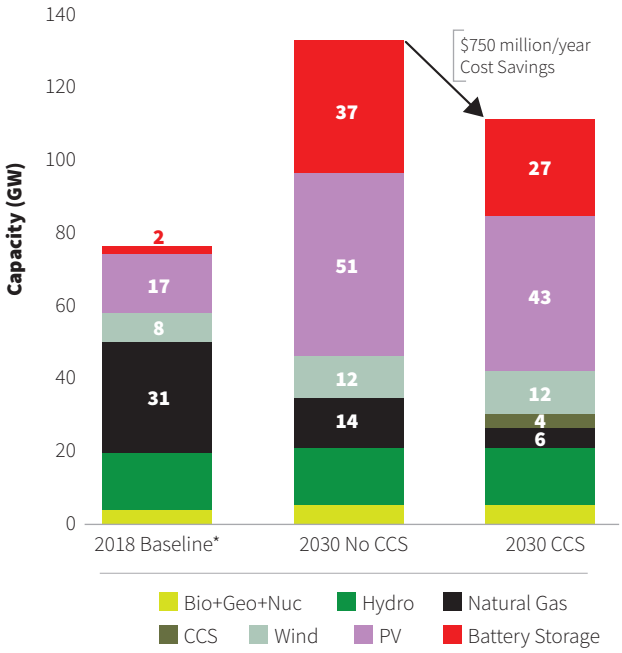
FIGURE 3-5

POTENTIAL NGCC RETROFIT SITES AND EXISTING GAS POWER PLANT SITES, 2018

This analysis found 25 NGCCs for potential CCS retrofit that could have a combined total annual capture potential of 27.5 $MtCO_2$. *Source: Energy Futures Initiative and Stanford University, 2020.*

FIGURE 3-6

CAPACITY OF CALIFORNIA'S ELECTRICITY SYSTEM IN 2030 WITH AND WITHOUT CCS



This figure shows system capacity in 2030 for a scenario with and without NGCC-CCS. The scenario with CCS shows approximately four GW of CCS in the system and overall lower capacity needs than a system without CCS. The annual generation system cost for a scenario with CCS is approximately $750 million/year lower as well. Note: Capacities include in-state generation capacity and out-of-state generation capacity dedicated to California. *2018 Baseline is California's generating capacity based on 2018 eGRID database including planned natural gas and nuclear retirements, as well as planned capacity additions for PV and wind. These adjustments are reflected in the 2030 scenarios as well. The capacities modeled are notional and not meant to inform reliability planning. The annual cost savings are rounded to the nearest $50 million. *Source: Energy Futures Initiative and Stanford University, 2020.*

The development of California's grid between 2018 and 2030 is being largely driven by the growth in load and meeting the 60 percent RPS and emission reduction goals. The costs of meeting these goals, especially their impacts on the state's economy and electricity affordability, should be important considerations for policymakers. In Figure 3-6, two cases are compared for meeting California's SB100 and SB32 emission reduction goals in 2030: one in which these goals are met by increasing renewables and battery storage alone; and one in which NGCC-CCS is allowed as an option.

As seen in Figure 3-6, having approximately four GW of NGCC-CCS reduces the solar photovoltaic (PV) and battery capacity required, and costs are approximately $750 million lower than the scenario without any NGCC-CCS.[g] In fact, NGCC-CCS complements significant growth in PV generation by operating at night throughout the entire year and during winter months when PV and wind output are low, as well as summer weeks with high peak loads.

The capacity of NGCC-CCS that is cost-effective in a 2030 grid, and the corresponding operating patterns, are consistent across a wide range of technology cost

g See Appendix B for electricity modeling assumptions.

assumptions: higher and lower battery storage costs, lower PV and wind costs, higher retrofit costs, and lower gas costs. System costs for scenarios with NGCC-CCS are consistently lower than scenarios without it. Four GW of NGCC-CCS on average corresponds to approximately six NGCC power plants being retrofit by 2030 and approximately 5.7 $MtCO_2$ captured annually by 2030.

The value of NGCC-CCS, despite relatively high capital and operating costs compared to intermittent renewable generation resources, is explained by the role CCS plays in reducing underutilization of other resources and providing a critical source of decarbonized energy and capacity when it is needed. The availability of NGCC-CCS reduces average curtailment of renewable generation by approximately 22 percent.[h] In short, NGCC-CCS is a "no-regrets" strategy for 2030, even in the face of several cost uncertainties.

In an electric grid that is expected to increasingly decarbonize, the value of NGCC-CCS will likely increase, and by 2045, become critical in meeting California's SB100 goals and economywide carbon neutrality. While there may also be other clean firm resources that can contribute to this role, CCS is a viable, cost-effective, commercially deployed, near-term technology that should be considered as an option within California's policy framework. Gaining experience with a relatively modest amount of NGCC-CCS by 2030 will help the state prepare in the event that NGCC-CCS is needed to meet the 2045 goals.

ASSESSMENT OF CO_2 STORAGE OPPORTUNITIES IN CALIFORNIA

California has one of the largest geologic storage potentials for CO_2 of any state, ranking in the top five for storage potential in oil and natural gas reservoirs, and in the top ten for storage potential in saline formations.[26] Recent estimates suggest that California has enough capacity in saline reservoirs and oil and gas fields to permanently store its annual economywide emissions at current levels for over 1,000 years.

Permanent storage can be done by injecting CO_2 into deep underground sedimentary rock formations that include saline formations or idle, depleted oil and gas fields. CO_2 can also be injected into an active oil or gas field to maintain pressure in the field and increase oil mobility, acting as a form of EOR. Injecting CO_2 into the subsurface is common practice for the oil and gas industry, with experience dating back to the early 1970s to maintain the overall pressure of an oil reservoir and increase recovery.

Safe, secure, and permanent geologic storage of CO_2 requires the presence of a sufficiently permeable rock formation, typically sandstone or carbonate, which is overlain by low permeability rocks, typically shales. The top of the reservoir needs to be 2,700 feet or deeper and the temperature above 31°C to ensure that the CO_2 is stored as a dense supercritical fluid. The geologic top seal must be continuous over the entire reservoir where the CO_2 is stored and free of permeable faults, fractures, or leaky wellbore penetrations. CO_2 storage is only permitted in saline reservoirs that have greater than 10,000 ppm total-dissolved-solids. Technical CO_2 storage risks are discussed further in Box 3-2.

BOX 3-2

CO_2 STORAGE RISKS

The potential risks of CO_2 storage include groundwater quality degradation, induced seismicity, natural resource damage, ecosystem degradation, and release to atmosphere.

However, according to the IPCC, "with appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environment **risks of geological storage would be comparable to risks of current activities**," such as CO_2-EOR. The successful experience for CO_2 storage from global CCS projects over the past two decades supports this assertion.[27]

Analysis by the IPCC also found that "the fraction [of CO_2] retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1,000 years."[28] Translation: the leakage risk is very low.

h Average curtailment is 9.8 TWh in 2030 in scenarios with CCS, and 12.6 TWh in 2030 in scenarios without.

Geologic storage of CO_2 in California also presents non-technical challenges that include regulatory uncertainty, post-injection site stewardship and liability, and the length of time required to demonstrate permanence. The CCS Protocol developed for the LCFS program provides guidelines to help address some of these issues, however, there are unresolved issues which are discussed in Chapter 4 – with proposed solutions described in Chapter 5.

California Geology

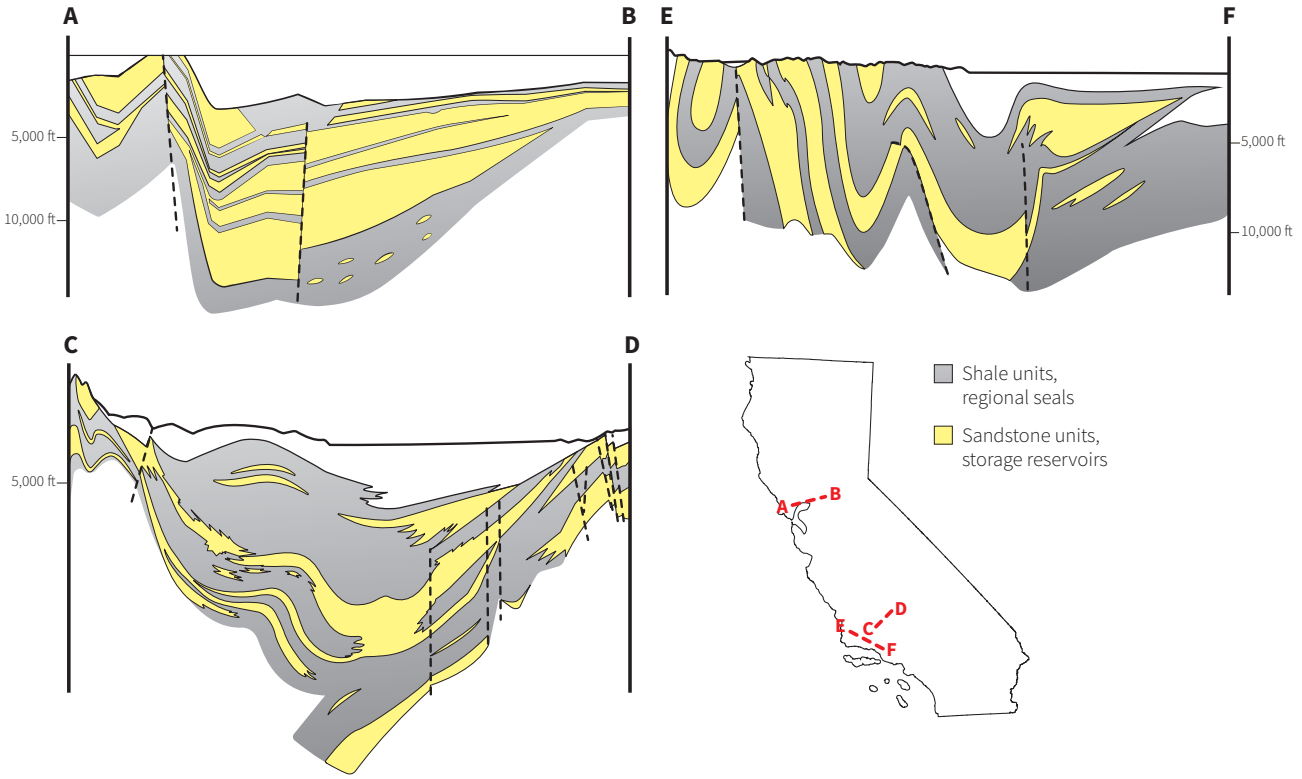
Several factors in key regions make California particularly well suited for CO_2 storage. Layers of thick alternating sands and shales and broad structural closures, the same elements that are useful for trapping large quantities of oil and gas, are present in both the Central Valley and Ventura Basins.

California's Central Valley is 450 miles long and 60 miles wide and is a depositional basin with sediment fill up to 50,000 feet thick.[29] Figure 3-7 contains a set of three schematic cross sections across the northern (through the southern part of the Sacramento Basin) and the southern (through the San Joaquin Basin) parts of the Central Valley. These cross sections illustrate some of the large reservoir

Several factors make California particularly well suited for CO_2 storage. Layers of thick alternating sands and shales and broad structural closures, the same elements that are useful for trapping large quantities of oil and gas, are present in both the Central Valley and Ventura Basins.

FIGURE 3-7

CROSS SECTIONS THROUGH THE CENTRAL VALLEY AND VENTURA BASIN



Schematic cross sections across the South Sacramento Basin (A-B), San Joaquin Basin (C-D), and Ventura Basin (E-F).
Source: Energy Futures Initiative and Stanford University. Adapted from WESTCARB, 2007.

units that have been exploited historically due to their vast petroleum resources, including some of the main sealing layers that trapped the petroleum and can also form a seal for any injected CO_2. The Ventura Basin lies within the Transverse Ranges of California and contains close to 60,000 feet of marine sediments. In Figure 3-7, the E-F cross section illustrates the tightly folded and faulted rocks that provide the traps for significant volumes of oil resources in this region.[30]

Previous Assessments of CO_2 Storage Capacity in California

A number of studies on CO_2 storage have concluded that California has an enormous capacity for storing CO_2.[31] The U.S. DOE supported the West Coast Regional Carbon Sequestration Partnership (WESTCARB), an organization led by the CEC, to carry out an assessment of the storage capacity in California. The study identified 104 sedimentary basins in California, 27 of which had significant CO_2 storage potential due to the presence of significant porous and permeable reservoir rocks, thick and pervasive seals at least 100 feet thick, and sufficient top depth.[32] Basins that were overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs administered lands, and military installations were excluded from consideration.

Based on this analysis, WESTCARB estimated the CO_2 storage capacity of saline formations in the ten largest basins in California ranged from 150 to 500 Gt, depending on assumptions about the fraction of the formations used and the fraction of the pore volume filled with supercritical-phase CO_2.[33] Further refinements of the WESTCARB studies were incorporated into the National Carbon Sequestration Database (NATCARB),[34] which was developed to link the distributed data from each of the Carbon Sequestration Regional Partnerships. The NATCARB estimate for CO_2 storage in California ranges from 30 to 417 Gt, with a mean estimate of 148 Gt. As noted, CO_2 emissions from California's electricity and industrial sectors totaled 166 $MtCO_2e$ in 2017,[35] 1,000 times less than the available storage capacity.

In 2013, the U.S. Geological Survey (USGS) completed an assessment of all technically accessible storage capacity for CO_2 in the United States.[36] This analysis was done using storage assessment units, which are either a single rock formation or an aggregation of a few rock formations within a basin (or sub-basin). The study limited the number of basins studied (the Los Angeles Basin, Sacramento Basin, San Joaquin Basin, and Ventura Basin) and did not evaluate basins along the coast or near the border with Mexico. It also modified the volumetric calculation to include average CO_2 density at mid-formation depth and added a storage efficiency factor to account for the fraction of trapping that can occur within a volume of porous rock. The USGS study concluded that California's storage capacity ranges from 67–120 Gt, with a mean estimate of 90 Gt.

In addition to evaluating the potential for storing CO_2 in saline reservoirs, the CO_2 storage capacity in existing oil and gas fields and underground gas storage (UGS) sites has been assessed. California has 503 oil and gas fields (combination of active and inactive/abandoned) and 13 UGS sites. WESTCARB screened reservoirs using depth, an American Petroleum Institute (API) gravity cutoff, and cumulative oil produced, and computed a total CO_2-EOR storage potential of 3.4 Gt.[37] The study suggested that gas reservoirs (former gas fields and UGS sites) could store another 1.7 Gt (for a total of 5.1 Gt). The NATCARB public access database estimates a CO_2 storage capacity for oil and gas fields and UGS sites in California to be from 3.6 to 6.6 Gt.[38]

CO_2 emissions from California's electricity and industrial sectors totaled 166 $MtCO_2e$ in 2017, 1,000 times less than the available storage capacity.

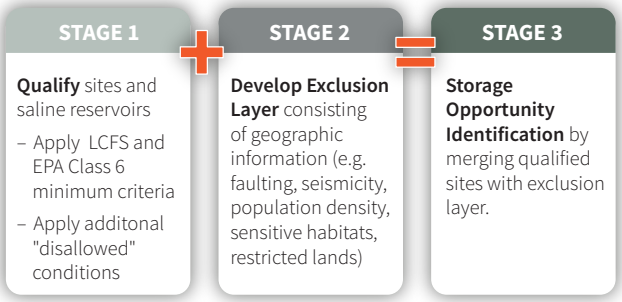
Evaluation Framework for Storage Potential

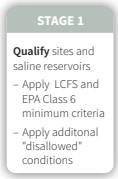
A three-stage evaluation (Figure 3-8) was conducted for this study to further assess the suitability of storage locations based on EPA regulations and CARB CCS project eligibility criteria. Stage 1 eliminated sites that did not meet qualifying criteria established by either the EPA,[39] the LCFS CCS Protocol,[40] or additional disallowed conditions

(discussed below). In Stage 2, additional geographic information (e.g. faulting, seismicity, sensitive habitats, population density, restricted lands) was used to develop an exclusion layer identifying regions where siting of a CO_2 storage facility is unacceptable. Finally, in Stage 3 the results of Stage 1 and Stage 2 were merged to identify prospective storage locations. Because this evaluation involves both geology and geography, maps are used to illustrate the process used to identify the best storage sites.

FIGURE 3-8

EVALUATION STAGES USED TO IDENTIFY STORAGE OPPORTUNITIES





Stage 1: Qualify Sites

The EPA[41] and CARB[42] have each established minimum siting criteria for CO_2 storage (Box 3-3). The EPA criteria applies to a Class VI injection well, which is used for CO_2 injection for long-term storage. The EPA criteria does not apply to an injection well used for CO_2-EOR operations. In addition to the EPA and LCFS CCS protocol minimum siting criteria, this study used two additional criteria for identifying appropriate storage sites:

Storage Capacity: Any oil or gas field or USG site that had an estimated mean CO_2 storage capacity of less than three Mt was eliminated from consideration. Large point sources will require storage formations with capacity on the order of 50 Mt or more. If a former or active oil/gas field or USG site is repurposed as a storage site (or EOR operation), it will need to have enough capacity to warrant the building of transportation infrastructure, hence the need for a minimum capacity cutoff. This criterion was not applied to saline reservoirs, as one could consider developing a CO_2 storage site in a saline reservoir directly below an emission source (eliminating the need for transportation infrastructure), perhaps reducing the need for such a large site storage capacity.

Injectivity: From a reservoir engineering perspective, injecting CO_2 requires a zone with an adequate combination of reservoir thickness, porosity, permeability, and pore pressure conditions. All oil and gas fields and UGS sites for which available data suggested that one or more of these parameters might hinder the ability to inject large quantities of CO_2 at sufficient rates were eliminated from consideration.

Most studies impose a salinity cutoff and do not consider reservoirs with less than 10,000 ppm of total dissolved solids as suitable for CO_2 storage. The intent is to protect potential future sources of drinking water from contamination. In this analysis, this requirement was relaxed for **active** oil fields; given the solubility of hydrocarbons in water, it is considered highly unlikely that water from an active oil field (even if low salinity) would ever be used for drinking water or agricultural purposes without significant treatment.

Saline Reservoirs: This analysis started with the USGS dataset because it was completed on a sub-basin and rock formation scale. However, because only four basins were included in the USGS dataset (USGS did not consider potential storage formations along the coast or near the Mexico border), the USGS dataset was supplemented with information on an additional seven basins from the NATCARB database. Applying the qualifying criteria from EPA, CARB, and additional criteria developed for this study, areal extent of potential saline storage has a mean capacity of 116 Gt, highlighted in light green in Figure 3-9.

Oil and Gas Fields and UGS sites: This evaluation of oil and gas fields and UGS sites relies primarily on data from NATCARB,[43] supplemented with data available from the CCST[44] and reports generated by the California Division of Oil, Gas, and Geothermal Resources (now CalGEM)[45,46,47,48]. Stage 1 qualifying criteria developed for this study reduced the number of oil and gas fields under consideration for CO_2 storage from 503 to 120, and USG sites from 13 down to nine. The result: the total CO_2 storage capacity in oil and gas reservoirs was reduced to 2.9–5.3 Gt, largely by the elimination of sites with small storage potential. The remaining oil and gas fields are seen in dark green and UGS sites are in red in Figure 3-9.

BOX 3-3

EPA AND CARB MINIMUM SITING CRITERIA FOR CO_2 STORAGE

EPA Minimum Criteria for Siting a Class VI Well [40 CFR 146.83]

Owners or operators of Class VI wells must demonstrate that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:

- An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream.
- Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).
- The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

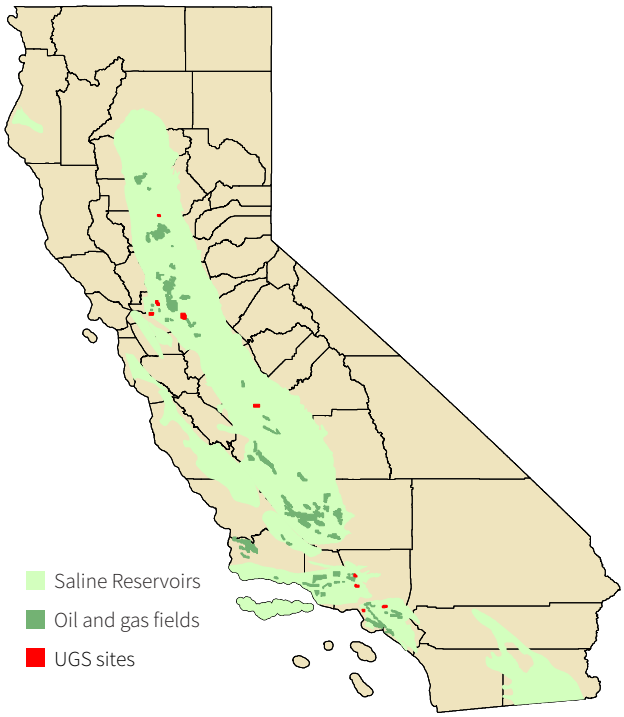
CARB Minimum Site Selection Criteria [LCFS CCS Protocol, Section 2.1]

As part of the application for LCFS Sequestration Site Certification, the CCS project operator must demonstrate that the geologic system comprises:

- A sequestration zone of sufficient volume, porosity, permeability, and injectivity to receive the total anticipated volume of the CO_2 stream.
- A minimum injection depth of 800 meters (m), or the depth corresponding to pressure and temperature conditions where CO_2 exists in a supercritical state [>31°C and >1,015 pounds per square inch (PSI)].
- A confining layer free of transmissive faults or fractures and of sufficient areal extent, integrity, thickness, and ductility to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining layer.
- A minimum of one additional permeable stratum (dissipation interval) situated directly above the sequestration zone and confining layer, with at least one impermeable confining layer (secondary confining layer) between the surface and the dissipation interval. The sequestration zone, primary confining layer, dissipation interval(s), and secondary confining layer(s) define the storage complex. The purpose of the dissipation interval is to (1) dissipate any excess pressure caused by CO_2 injection, (2) impede vertical migration of CO_2 and/or brine above the storage complex, potentially to the surface and atmosphere via possible leakage paths, and (3) provide additional opportunities for monitoring, measurement, and verification of containment.
- Depending on the distance between the sequestration zone and basement rock, the Executive Officer may require the CCS project operator to identify and characterize additional dissipation interval(s) below the storage complex to limit the extent of downward overpressure propagation and lower the potential for induced seismicity within formations beneath the injection zone.

FIGURE 3-9

RESULTS AFTER STAGE 1



Saline reservoirs (light green), oil and gas fields (green) and USG sites (red) after applying qualifying criteria (stage 1). *Source: Energy Futures Initiative and Stanford University, 2020.*

STAGE 2

Develop Exclusion Layer consisting of geographic information (e.g. faulting, seismicity, population density, sensitive habitats, restricted lands)

Stage 2: Develop Exclusion Layer

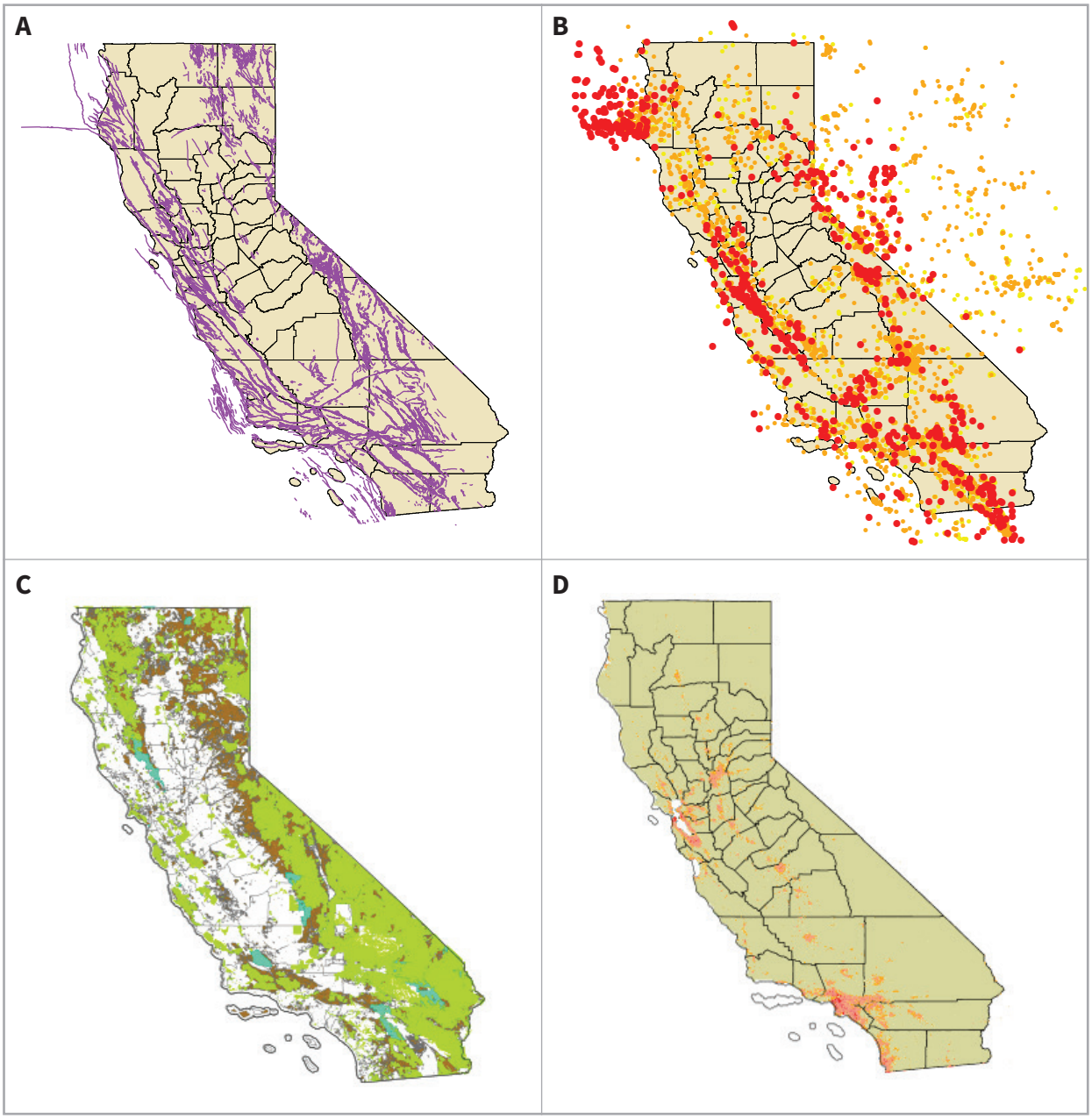
After developing the list of qualified oil and gas fields, UGS sites, and saline reservoirs, an exclusion zone was developed in Stage 2 based on available geographic information: geologic information, including seismicity and proximity to faults; surface features; and land use, e.g., population density, sensitive habitats, and restricted lands. The range of characteristics considered for establishing this zone are illustrated in Figure 3-10. Finally, more specifically, criteria for identifying exclusion zones included:

- **Faults** - Mapped quaternary faults are a potential risk for long term storage of CO_2. We included a four kilometer (km) "buffer zone" around each previously mapped fault.
- **Seismicity** – Active seismicity is another potential risk for long-term storage of CO_2.[49] We included a 10 km diameter "buffer zone" around locations with recorded earthquakes of magnitude five and higher, and a five km diameter "buffer zone" around locations with recorded earthquakes of magnitudes less than five. Seismic risks are discussed further in Box 3-4.
- **Sensitive habitats** – Excluded areas designated as critical wildlife habitat for certain species (e.g. desert tortoise, sharp tailed grouse) and wilderness study areas.[50]
- **Restricted lands** – These include national landmarks, conservation lands, military installations, American Indian lands, Federal lands, and State lands.[51]
- **Population Density** – Using data obtained from the Oak Ridge National Laboratory LandScan Global 2018 database,[52] which contains community population distribution data for the world on a one km by one km grid spacing, we eliminated any region in California with a population density of more than 75 people per square kilometer.

While a subset of 53 active oil fields in California were evaluated in a DOE study[53] and "screened acceptable" for CO_2-EOR, some of these fields fall within the exclusion zone identified by the criteria developed for this analysis. The entire Los Angeles basin was excluded due to population density, seismicity, and extensive faulting; in other areas, the criteria were slightly relaxed where there are 18 currently operating oil fields and moderate population density.

FIGURE 3-10

INPUTS TO STAGE 2 OF THE SCREENING PROCESS FOR SALINE RESERVOIRS



Geographic layers combined to establish "exclusion zone" include: A. Location of faults and associated buffer zones. B. Location of seismic events of greater than magnitude and associated buffer zones. C. Location of sensitive habitats. D. Population density. *Source: Energy Futures Initiative and Stanford University, 2020.*

BOX 3-4

SEISMIC RISKS

Subsurface fluid injection has the potential to induce earthquakes. CARB's LCFS CCS Protocol requires:

- An evaluation of the **seismic history** of the proposed sequestration site, including the date, magnitude, depth, and location of the epicenter of seismic sources and a determination that the seismicity would not cause a catastrophic loss of containment, either by breaching the integrity of the well or the sequestration formation. (Section 2.3)
- The Monitoring, Measurement, and Verification Plan must be submitted as part of the Testing and Monitoring Plan with the application for Sequestration Site Certification. The plan must include the methods the CCS Project Operator will perform to monitor the extent of the CO_2 plume and pressure front, the surface, and **seismic activity**. (Section 4.3.2)

TABLE 3-2

STORAGE CAPACITY ESTIMATES

Saline Reservoirs	Mean	
UGSG supplemented with NATCARB	116 Gt	
Qualified (end of Stage 1)	116 Gt	
Storage Opportunities (end of Stage 3)	69.1 Gt	
Oil and Gas Reservoirs	**Low**	**High**
NATCARB	3.6 Gt	6.6 Gt
Qualified (end of Stage 1)	2.9 Gt	5.3 Gt
Storage Opportunities (end of Stage 3)	1.1 Gt	2.1 Gt

STAGE 3

Storage Opportunity Identification by merging qualified sites with exclusion layer.

Stage 3: Opportunity Identification

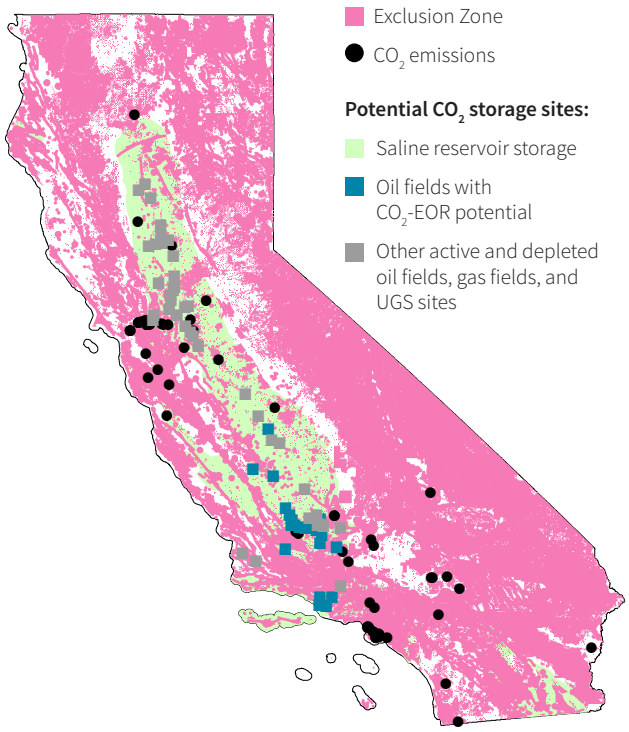
Stage 3 identified storage opportunities by layering the exclusion zones on top of oil and gas fields, UGS sites, and saline reservoirs that were identified in Stage 1, to delineate areas that were inappropriate for CO_2 storage and to identify the universe of qualified areas as possible sites for CO_2 storage.

Oil and gas fields (59 out of 120) and UGS sites (three out of nine) that did not fall within the exclusion zone were included as eligible sites. In some instances, only a portion of a field was covered by the exclusion zone; if that portion of the field not covered by the exclusion zone exceeded the three $MtCO_2$ capacity limit, it was included in the totals for possible storage capacity. Total capacity for potential storage of CO2 in California at these 62 oil and gas field sites is 1.1 to 2.1 Gt (Table 3-2).

The volume of saline reservoir storage that was not covered by the exclusion layer was computed by assuming a homogeneous or uniform capacity estimate per surface area eliminating portions of saline reservoirs covered by the exclusion zone. Total remaining volume was 69.1 Gt. The resulting region of potential storage as well as the emission sources identified earlier in this chapter as suitable for retrofit is illustrated in Figure 3-11.

FIGURE 3-11

POTENTIAL SOURCES AND SINKS



This figure details the potential emissions sources and sinks identified after stages 1, 2, and 3 of this analysis. *Source: Energy Futures Initiative and Stanford University, 2020.*

Assessment of CO_2 Storage Capacity in California

Based on this analysis, the combined CO_2 storage potential at saline reservoirs and oil and gas fields in the state of California is around 70 Gt. The state of California 2020 California GHG emissions limit is 431 $MtCO_2e$.[54] Assuming facilities are developed to capture 60 $MtCO_2$/yr, the state has enough storage capacity for over 1,100 years.

A "large-scale" CCS project (e.g. Petra Nova in Texas) stores around 1.6 $MtCO_2$/yr and a few super projects (e.g. Shute Creek in Wyoming) store around seven $MtCO_2$/yr. California is likely to need between 15 to 65 CO_2 storage sites to store CO_2 emissions from its electricity and industrial emission sources.

CCS INFRASTRUCTURE DEVELOPMENT OPPORTUNITIES IN CALIFORNIA

Deploying CCS infrastructure on a massive scale requires careful and comprehensive modeling to ensure that investments are made in a resilient and cost-effective manner. To better understand infrastructure development opportunities in California, this analysis included the following:

- **Integrated system design,** linking emissions sources with potential storage locations;
- **The revenue generating potential of the industrial and electricity units retrofit with CCS** and the impact of incentives on these projects; and
- **Community Impacts** to assess the potential local health and economic impacts of CCS infrastructure.

Integrated System Design

To link CO_2 sources with CO_2 storage sites—"sinks"—and assess potential project development opportunities, this analysis optimized cost-effective locations and quantities of CO_2 that can be captured, transported via pipeline, and injected for storage. The analysis examines sources by location, size, and facility type; sinks; and infrastructure needs for scenarios requiring the storage of 10, 30, and 59[i] $MtCO_2$/yr. The results of this analysis are summarized in Table 3-3.

The approximate physical locations of CO_2 sources, optimized pipeline routes, and CO_2 storage sites for the three scenarios—10, 30 and 59 $MtCO_2$ captured, transported and stored per year—are illustrated in Figure 3-12.[j] This analysis used SimCCS,[55] a high-level software screening tool; it is not meant to dictate actual pipeline routes. It does however, inform an integrated system design ranging from single facilities to large, regional networks involving multiple CO_2 emission sources and geologic sinks.

The project development opportunities identified in this analysis include a mix of potentially co-located options where transportation of CO_2 is not required, as well as opportunities involving the need to consider pipelines or other transportation options.

Co-located options, where the emission source lies directly above the potential saline reservoir, could capture and store 5.6 $MtCO_2$/yr of emissions (three ethanol plants, two CHPs and five NGCCs). An additional 4.1 $MtCO_2$/yr (two CHPs and three NGCCs) of emission sources are within 10 miles of suitable CO_2 storage, and would require minimal infrastructure development. All of these involve emission sources in the Central Valley. The remaining 50 $MtCO_2$/yr of capturable emissions identified in this study require development of a transportation infrastructure, requiring up to 1,150 miles of new pipelines.

Pipelines for transporting CO_2 are well-established infrastructure. There are at least 4,500 miles of CO_2 pipelines in the western U.S., which transport more than 50 $MtCO_2$/yr of naturally occurring CO_2 to EOR projects in west Texas and other oil-producing regions in the country.[56] Most CO_2 pipelines operate in a 'dense phase' mode and at ambient temperature and high pressure. Pipeline transport of CO_2 requires compressing gaseous CO_2 to a pressure above 1,160 PSI to ensure flow of liquid CO_2. In most of these pipelines, the flow is driven by compressors at the emission source with intermediate compressor stations along the route. Pressures in CO_2 pipelines are higher than in natural gas pipelines, so existing infrastructure cannot be used interchangeably.

i 59 $MtCO_2$/yr was used as the maximum for the integrated system modeling because it was the total volume of capturable emissions identified in this study.

j Each model run is separate and independent, meaning that the 30 $MtCO_2$/yr case does not build on the 10 $MtCO_2$/yr case.

TABLE 3-3

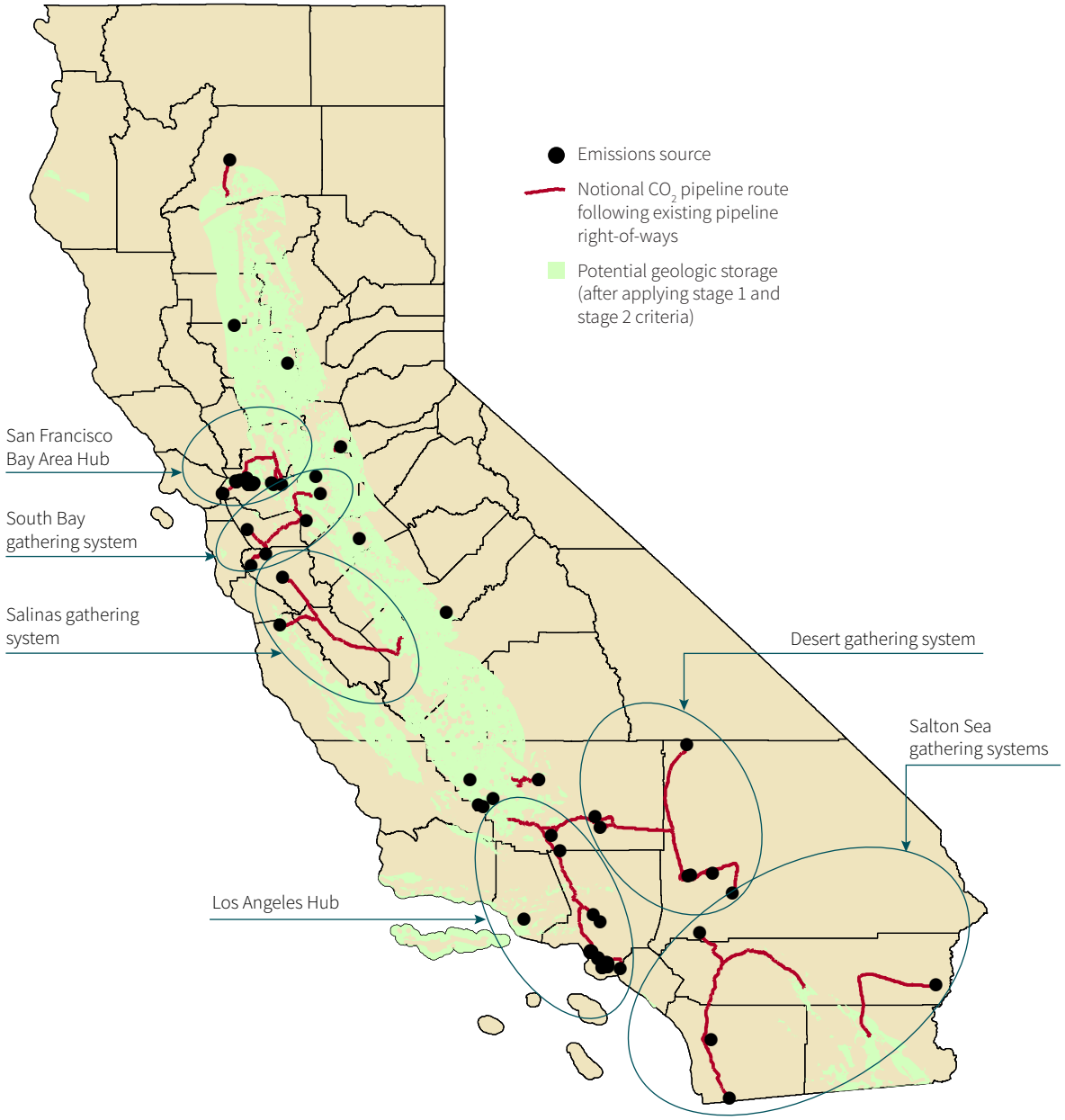
PROJECTS, VOLUMES, AND INFRASTRUCTURE NEEDS

Project Development	10 $MtCO_2$/yr	30 $MtCO_2$/yr	59 $MtCO_2$/yr
San Francisco Bay Area hub with gathering system and storage in Sacramento Basin	**Sources**: 3 hydrogen, 3 refineries **Sink**: 4.7 $MtCO_2$/yr 60 miles of pipeline	**Sources**: 8 hydrogen, 4 refineries, 5 CHPS **Sink**: 9.6 $MtCO_2$/yr 70 miles of pipeline	**Sources**: 8 hydrogen, 4 refineries, 6 CHPS, 3 NGCCs **Sink**: 14 $MtCO_2$/yr 100 miles of pipeline
Los Angeles hub with gathering system and trunk line	**Sources**: 1 hydrogen, 3 refineries, 1 CHP **Sink**: 4.9 $MtCO_2$/yr 100 miles of pipeline	**Sources**: 8 hydrogen, 5 refineries, 4 CHPs, 1 cement **Sink**: 15.9 $MtCO_2$/yr 160 miles of pipeline	**Sources**: 8 hydrogen, 5 refineries, 3 CHPs, 1 cement, 5 NGCCs **Sink**: 25.2 $MtCO_2$/yr 200 miles of pipeline
Co-located (or short pipeline) sink in the Central Valley	**Sources**: 3 ethanol **Sink**: 0.4 $MtCO_2$/yr	**Sources**: 3 ethanol, 2 NGCC, 1 CHP **Sink**: 3.9 $MtCO_2$/yr	**Sources**: 3 ethanol, 6 NGCCs, 5 CHPs, 1 cement **Sink**: 8.4 $MtCO_2$/yr
Desert Gathering System (joins the LA trunkline above)		**Sources**: 5 cement **Sink**: Joins w/ LA Hub 220 miles of pipeline	**Sources**: 5 cement, 1 CHP, 2 NGCCs **Sink**: Joins w/ LA Hub 290 miles of pipeline
Salton Sea Gathering Systems			**Sources**: 4 NGCCs **Sink**: 5.2 $MtCO_2$/yr 300 miles of pipeline
South Bay Area Gathering System			**Sources**: 1 cement, 3 NGCCs **Sink**: 3.3 M CO_2/yr 100 miles of pipeline
Salinas Area Gathering System			**Sources**: 2 NGCCs **Sink**: 3.0 MtCO2/yr 135 miles of pipeline

Pipelines for transporting CO_2 are well-established infrastructure. There are at least 4,500 miles of CO_2 pipelines in the western U.S., which transport more than 50 $MtCO_2$/yr of naturally occurring CO_2 to EOR projects in west Texas and other oil-producing regions in the country.

FIGURE 3-12

CCS PROJECT DEVELOPMENT OPPORTUNITIES



Map illustrates potential project development opportunities that together abate 59 $MtCO_2$/yr. Pipeline routings are 'notional' and follow existing pipeline right-of-ways. Sink locations are not intended to be exact locations for geologic storage. *Source: Energy Futures Initiative and Stanford University, 2020.*

Estimates for pipeline transportation costs vary depending on pipeline diameter, distance, topography, numbers of pumping stations, and other local factors. A survey of costs ranges from \$1.3/tCO_2 for a large pipeline carrying 30 MtCO_2/yr to as high as \$10.90/tCO_2 for a smaller pipeline transporting three MtCO_2/yr.[67] More recent analyses by Lawrence Livermore National Laboratory (LLNL)[68] and the National Petroleum Council (NPC),[69] using SimsCCS, fall within this range, averaging \$4.07/tCO_2. While transportation costs have only a small impact on project economics (compared to capture costs, storage costs, and CCS incentives like 45Q and LCFS), challenges with building and permitting a pipeline are significant and are discussed in greater detail in Chapter 4. Alternative modes of transport are discussed in Box 3-5.

Revenue Generating Potential of Electricity and Industrial CCS in California

Technoeconomic modeling was conducted to better understand the revenue generating capacity of the 76 emission sources identified in this analysis, assessing whether revenues can be generated by an operating facility over the course of a year. More detailed financial models from the developer perspective are discussed later in this chapter in the section titled "Project Development Opportunities." The assumptions used to model the costs of CCS for the 25 electricity and 51 industrial facilities identified earlier in this chapter include incentives, capital recovery factor, and storage costs. They do not, however, take into account innovative project business models that could impact the profitability of a project. Assumptions to assess project revenue generating potential are detailed in Box 3-6.

BOX 3-5

ALTERNATIVES TO CO_2 TRANSPORT BY PIPELINE

Although pipeline transport may theoretically be a highly economic means for moving CO_2, other methods may be more advantageous in the short-term, while awaiting pipeline rights and construction, or long-term, depending on the amount of CO_2 and distance required for transport.

Truck. Cryogenic trucks are already widely used to transport CO_2 for the beverage industry.[57] A typical load may range from 18[58] to 22[59] tons, rendering this method unsuitable for large industrial emitters, though it may accommodate smaller emitters, such as biomass generation. Economic analysis suggests truck transport is most viable for short distances (<20 miles),[60] though it could also play an intermediate role in delivering CO_2 to a pipeline or railcar.[61]

Rail. Refrigerated and pressurized railcars make use of existing rail infrastructure to transport massive amounts of CO_2 across long distances, and already move hundreds of thousands of tons per year across North America.[62] Rail transport can handle CO_2 from large emitters, and compares favorably cost-wise to pipelines for flowrates up to 2,000 tCO_2 per day.[63] However, as CCS infrastructure develops, pipelines ultimately appear more economical for handling large volumes from multiple sources.[64]

Boat. Shipping is not particularly viable either in California or the continental U.S. as a whole, although it could potentially prove more economical at moving large volumes across long distances compared to a coast-to-coast pipeline.[65] Shipping may ultimately be most useful for importing other countries' CO_2 for storage, taking advantage of the great storage capacity of American geology.[66]

BOX 3-6

ASSUMPTIONS FOR ASSESSING PROJECT REVENUE GENERATING POTENTIAL

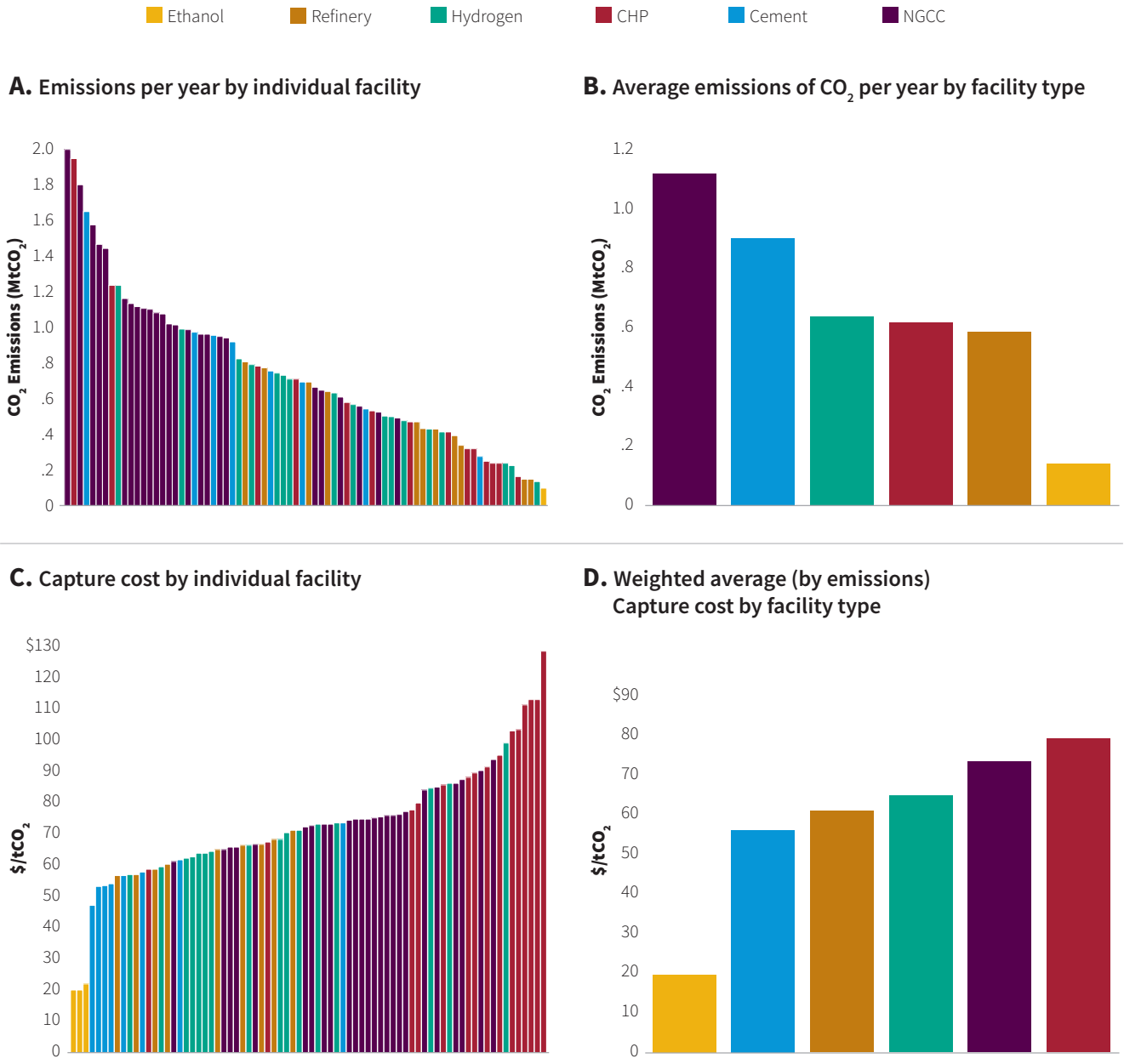
- **LCFS credit price**: \$100/tCO_2. A credit price of \$100/tCO_2 is much less than current levels (September 2020, \$196/tCO_2),[70] but is in line with CARB's estimated LCFS prices with proposed amendments.[71]
- **Capital Recovery Factor (CRF)**: 10 percent for NGCCs and 13 percent for all other industrial emitters. This analysis assumed that a highly regulated entity would only need a CRF of 10 percent while the competitive heavy industry would need a CRF of at least 13 percent to attract investors.
- **Storage costs for non-EOR fields and saline reservoirs**: The DOE estimates saline storage costs to range from \$7-13/tCO_2. This analysis used the midpoint of the DOE high and low estimates and used a cost of \$10/tCO_2. When coupled with the 45Q credit for storage in saline reservoirs, this results in a net revenue of \$40/tCO_2. Storage costs will vary by project in part due to the quality and knowledge of the resource.
- **Storage costs for EOR fields**: Although EOR fields will have associated storage costs, the project economics will benefit from sales of produced oil. For this analysis, and the subsequent sink/source pairing, it was assumed that fields undergoing CO_2 EOR would benefit from a net revenue of \$5/tCO_2. When coupled with the 45Q credit for EOR, this results in a total revenue of \$40/tCO2 to the storage facility – the same value assumed for non-EOR storage. This was done to ensure that that there was no preference given to any sink type (EOR or non-EOR) in the subsequent pairing analysis (which is discussed in the section titled "Infrastructure and Project Development in California").
- **Cap-and-trade eligibility**: None
- **Transportation cost**: Not included in technoeconomic analysis as these costs are dependent on source and sink pairings.

The emissions volumes from the 76 identified sources for CCS retrofit are shown in Figure 3-13A. A similar graph using the same data but aggregated by industry is shown in Figure 3-13B. Together, these graphs illustrate which industries have the highest emissions: NGCCs, followed by cement, then hydrogen, CHPs and refineries (these three are about the same), and finally ethanol, which is much lower. Capture costs are shown in the second set of graphs (Figure 3-13C & 3-13D), these graphs clearly illustrate which emissions are less costly to abate (ethanol and cement) and which are most costly (generally CHPs).

While the primary objective of CCS projects is to reduce CO_2 emissions and mitigate climate change, the technical characteristics of post-combustion capture could also reduce emissions of criteria air pollutant emissions from certain facilities... Emissions sources with higher levels of pollutants... will see greater air quality improvements from CCS.

FIGURE 3-13

COMPARISON OF EMISSIONS AND CAPTURE COST (BY FACILITY AND SUBSECTOR)



Emissions volumes and capture costs for the 76 candidate facilities analyzed in this study. *Source: Energy Futures Initiative and Stanford University, 2020.*

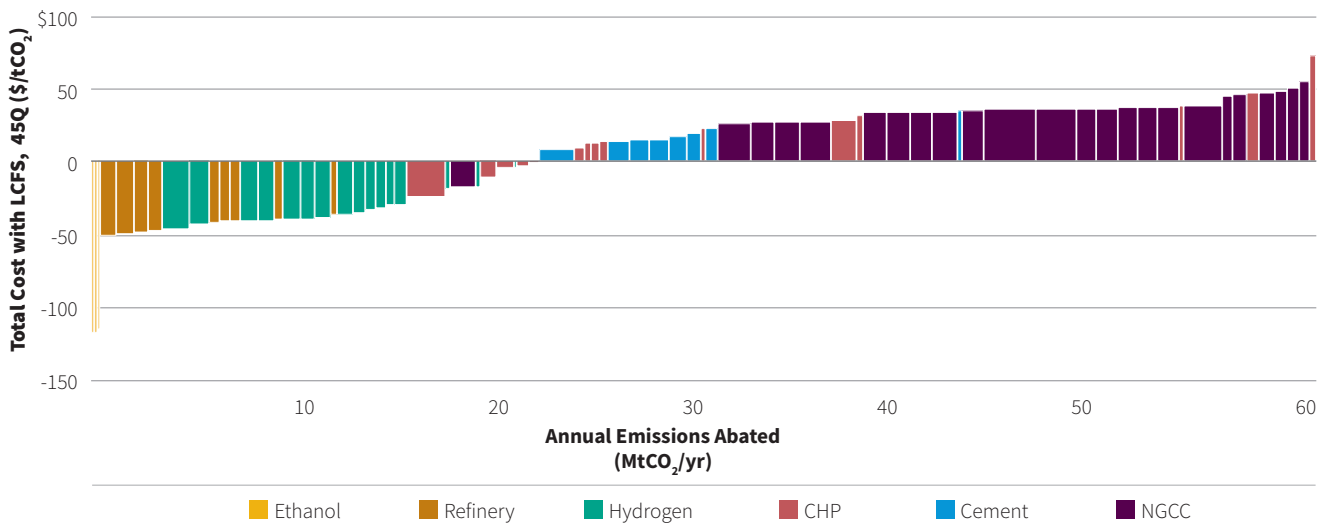
The marginal abatement curve (excluding transportation costs) shows the total cost of abatement[k] for each of the 76 emitting facilities (Figure 3-14). Ethanol, refining, and hydrogen projects can generate positive revenue, CHPs are mixed (depending on LCFS eligibility), and cement and NGCCs do not generate positive revenues. These curves show that 34 facilities can generate positive revenue with CCS and could abate 21.5 $MtCO_2$/yr.

This analysis also shows that:

- **Ethanol** has the lowest capture cost, is eligible for LCFS credits, and has the highest revenue. However, the emissions volumes are small. Ethanol is a clear early target for CCS project development. The three ethanol plants in California are also conveniently situated in the Central Valley and co-located with saline reservoir storage.
- **Hydrogen** and **Refining** sectors have medium capture costs, but with LCFS and 45Q credits they net a positive revenue. These industrial facilities are typically located in major metropolitan areas and captured CO_2 will require transport to suitable storage (at additional cost).
- **CHP** facilities in California are associated with either refining operations, upstream oil and gas operations, or non-petroleum industry applications. Those associated with the petroleum industry are eligible for LCFS credits (or a portion of the emissions may be eligible in the case of upstream operations). CHP facilities have high capture costs, and many do not generate positive net revenue even with LCFS and 45Q.
- **Cement** capture costs are relatively low, but given that cement is not eligible for LCFS, the only revenues are from 45Q. This revenue is not enough to offset the capture costs, such that total revenue is negative. Cement facilities are further burdened with comparatively large CO_2 pipeline transportation costs due to their locations, which, in California, are typically distant from suitable storage.
- **NGCCs** have relatively high capture costs and are not eligible for LCFS except for any portion eligible for fuel pathways (e.g. share of electricity generated at Elk Hills that powers its oil field operations). However, as noted earlier this chapter in the section titled "Value of CCS in the Electricity Sector in the Near-Term," NGCC with CCS-retrofit is a cost-effective way for California to meet its SB100 objectives.

FIGURE 3-14

MARGINAL ABATEMENT CURVE BY FACILITY



The 34 facilities on the left side of the graph that show negative costs can generate positive revenues. The opposite is true for the 42 facilities on the right side of the graph. Note that the crossover on this graph from negative to positive costs occurs at 21.5 $MtCO_2$/yr abated.
Source: Energy Futures Initiative and Stanford University, 2020.

k Abatement cost = capture cost ($/t$CO_2$) + storage cost ($/tCO_2) plus incentives (LCFS and 45Q credits where applicable, in $/t$CO_2$)

Community Impact Analysis

There are complex and interrelated issues regarding how CCS may impact local communities, especially in neighborhoods where residents live just outside the fence line of major emission sources. Both economic and technical reasons explain why facilities with high emissions of Criteria Air Pollutants (CAPs), such as sulfur dioxide (SO_2), nitrous oxide (NO), nitrous dioxide (NO_2), and particulates, are also large CO_2 emitters.[l] Residents who live next to these high-emitting plants are exposed to outdoor and indoor concentrations of CAPs that are known to be deleterious to health.

While the primary objective of CCS is to reduce CO_2 emissions and mitigate climate change, post-combustion capture could also reduce emissions of criteria air pollutant emissions from certain facilities. CCS projects also bring economic benefits, such as job creation from temporary construction, permanent positions related to capture facility operations, as well as opportunities along the supply chain.

Why High Criteria Air Pollutants and Greenhouse Gas Emissions are Often Correlated

Fundamentally, the heaviest CO_2 emitters, both in terms of absolute mass and in terms of mass of CO_2 per unit of production, tend to be plants that combust high-carbon fuels for heat and/or power, particularly solid fuels such as petroleum coke and coal. The cement industry is, for example, highly competitive; cheap fuels, such as coal and petroleum coke, improve plant economics.[72]

In refining, the major CO_2 emitter is the FCCU, which converts heavier portions of feedstock into lighter ultimate product. The heavier the slate of crudes processed at a refinery (including California crudes and Canadian tar sands)[m], the greater the per barrel CO_2 and sulfur. In contrast, while natural gas power plants are a major source of CO_2 emissions in California, natural gas contains no ash and negligible amounts of sulfur; for any given amount of fuel [measured in million British Thermal Units (MMBtu)] combusted at a site, natural gas-fired processes will tend to have low CO_2, low sulfur, and low particulate emissions relative to coal- or pet coke-fired combustion.[73] There is less of a correlation between high carbon versus low carbon fuel combustion and NO_X (a combined measure including NO and NO_2).

Why CCS Could Reduce Criteria Air Pollutant Emissions

CAP emissions could be reduced when CCS systems are installed for two reasons. First, engineering specifications for CCS retrofit systems require the to-be-treated stack gases to be relatively free of SO_2 and particulate matter. Second, if the installation of the CCS system is treated as a "significant modification" of the emitter's equipment, the emitter may become subject to current (usually tighter) emissions standards (detailed in Chapter 2). Facilities that have already been subject to very stringent local air regulation standards on CAPs are less likely to show large tonnage or percentage reductions in CAPS after installing capture equipment.

l The same sites that are large CO_2 and CAP emitters are often large emitters of Hazardous Air Pollutants, especially Volatile Organic Compounds and/or a variety of heavy metals. The limited scope of this analysis precludes addressing these, but many of the same considerations relating to CAPs may also apply to Hazardous Air Pollutants.

m Crudes with "API gravity" above ~30 are considered "light," and crudes with sulfur below ~0.5% are considered "sweet." Kern River (CA) crude is reported by Standard & Poor's to be 13.2 API and 1.13% sulfur, and Canadian "Cold Lake" is 20.1 API and 3.75% sulfur. By contrast, Bakken crude is 42.3 API and 0.12% sulfur; Compared to Bakken, Kern is about three times heavier and has eleven times more sulfur.

The possible co-benefits of CCS retrofits include:

- **Complete elimination of SO_2** emissions when amine solvent based carbon capture systems are installed. SO_2 is a serious contaminant for these amine systems and high levels of SO_2 in the untreated feed gases to the CCS system rapidly destroy the costly solvent.[74]
- **A significant reduction in particulate emissions** through pre-treatment (i.e., before the gas stream reaches the inlet of the CCS system) if initial levels of particulates exceed the permissible—relatively low—thresholds for amine systems. Emissions impacts on particulate (PM10 or PM2.5)[n] are not well studied, or in some cases are simply not well-disclosed because the information is treated as highly confidential and proprietary by amine system purveyors.
- **Reductions in NO_2 emissions**, as they may to be reduced before CCS can be installed, depending on the starting NO_2 concentrations. The IEA's 2008 study of cement carbon capture[75] states, for example, "Concentrations of NO_2 in the flue gas should be restricted to approximately 41mg/Nm^3 (20 ppm by volume at six percent oxygen)[o] for economic post-combustion capture using amine."[76]

This analysis assumes that NGCC units and industrial facilities continue to operate. The potential air quality benefits resulting from CCS retrofit on various types of facilities is an important topic that requires further research and analysis.

Poverty and Unemployment Indicator and Jobs Analysis

Poverty and unemployment indicators from the CalEnviroScreen 3.0 tool[77,p] were used, among other things, to gain insight as to where CCS development may occur in relation to socioeconomically disadvantaged communities. Historically, these communities have had to bear the brunt of industrial and power development with limited compensation or community benefit. Although pipeline construction and CO_2 storage projects can provide economic benefits to host communities such as jobs, revenues from land leases, and other provisions negotiated in Community Benefit Agreements (CBAs), infrastructure projects are often undertaken without ensuring that the economic benefits accrue in full or in part to the communities where projects are located. Also, projects are frequently planned without gaining community buy-in and support.

The screening criteria, when compared to the locations of the emission sinks, pipeline routes, and potential storage sinks, show the following:

- 24 out of 76 sources (31 percent) fall in the high unemployment tracts
- 13 out of 76 sources (17 percent) fall in the high poverty tracts
- 43 percent of the pipeline (510 of 1,190 miles) falls within high unemployment tracts
- 28 percent of the pipeline network (330 of 1,190 miles) falls within high poverty tracts
- 13 of the 22 (59 percent) CO_2 sinks fall within the high unemployment tracts
- Eight of 22 (36 percent) sinks fall within the high poverty tracts

n Airborne particulate matter (PM) is a mixture of many pollutants which vary in size, shape, and composition. Those with a diameter of 10 microns or less (PM10) can be inhaled into the lungs and cause adverse effects. Those with a diameter of 2.5 microns or less (PM2.5) are a subset of PM10 and often derive from different emission sources, including combustion of gasoline, oil, and diesel fuel.

o Nm3 is Normal meter cubed per hour, a unit used to measure gas flow rate.

p CalEnviroScreen is a tool created by the Office of Environmental Health Hazard Assessment for California Environmental Protection Agency (CalEPA) to enable the agency to analyze the impacts of multiple pollution sources in California communities as detailed in its 2004 Environmental Justice Action Plan.

CCS projects create jobs during construction and ongoing facility operations, as well as along the supply chain. If 25 percent of all CO_2 emissions from the power sector were captured across the U.S., employment in the capture segment of the CCS industry could reach the scale of the petroleum refining industry, and employment in the storage segment of the industry would be about one-fifth of the size of the oil and gas production industry.[78] Not unlike solar facilities where most of the jobs are in construction, at a typical CCS plant, about 2,000 people would be employed at a typical CCS plant employed during peak construction. When the facility is complete and shifts into long-term operation, the plant usually employs about 20 people.[79]

Although the long-term operation and management jobs at CCS facilities are fewer in number than the short-term construction jobs, it is important to note that the CCS industry also has multiplier effects across the supply chain and can drive employment gains outside of CCS facilities. Studies focused on Europe and the UK have estimated that approximately 40 to 70 percent of total additional jobs from a large-scale, future CCS industry would be indirect jobs associated with the supply chain.[80]

Project Development Opportunities: Three Cases by Facility Type

This section offers some insights on project development from the perspective of an investor. It does so with using a fictional entity, "ProjectCo"— a company formed for the purpose of capturing (and in some cases) storing CO_2, a device that is used inform the analysis of investor needs and options for a range of possible project types. The explored projects—three "cases"—are illustrative of the opportunities identified earlier in this chapter in Table 3-3:

- Case #1: **Ethanol production** with co-located geologic storage
- Case #2: **NGCC** electricity generation with co-located geologic storage; and
- Case #3: A petroleum **refinery hub** (hydrogen production, CHP, FCCU) with offsite geologic storage.

The revenue and cost challenges for each are highlighted, as well as the effect on modeled returns measured by the project's internal rate of return (IRR). The details of the financial model from which the results are derived — including an explanation of its logic and all baseline assumptions — is found in Appendix C. In each case detailed and illustrated below, "ProjectCo" is identified by the shaded grey area. Cash flow assumptions are discussed in Box 3-7. Step changes in cash flows are typically due to assumptions around 45Q and/or LCFS duration.

BOX 3-7

ASSUMPTIONS FOR PROJECT CASH FLOW SCHEDULE

- 2021 – 2023 FEED
- 2024 – 2026 Construction
- 2026 Commence Operations
- 45Q received 2026 – 2038 (12 years)
- LCFS received 2026 – 2041 (15 years)- NGCC not LCFS eligible
- Project life 20 years (2026-2046)[q]

For additional details, please refer to Appendix C: Financial Modeling Assumptions and Details.

q It is possible that operations may cease prior to 20 years if cash flows go negative.

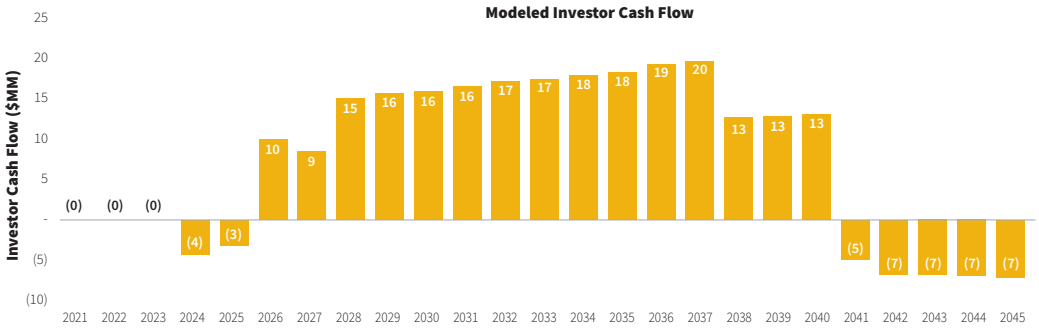
Case #1. Ethanol Production with Co-located Geologic Storage

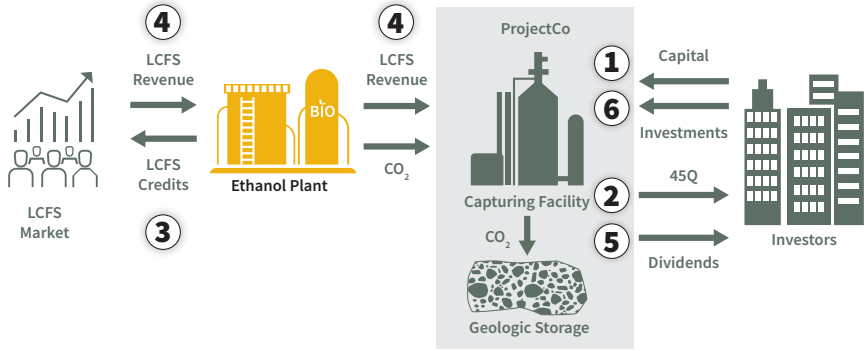
The general business configuration and associated cashflows for an ethanol production facility with carbon capture and co-located storage is provided in Figure 3-15. In this case, the capture facility, along with any gathering pipeline and storage infrastructure is managed by ProjectCo; the ethanol production facility owner(s) have a majority equity stake.

Ethanol with co-located geologic storage would achieve an IRR >15 percent and positive net present value (NPV). Beyond the eligibility of this kind of project to produce and sell LCFS credits and access to 45Q, it also benefits from a low-cost FEED study and low capital costs. Returns are reduced, however, because the financial responsibility bond required as part of UIC Class VI permitting is borne fully by the project, presuming the site stores only that CO_2 produced by the ethanol facility.

FIGURE 3-15

GENERAL BUSINESS CONFIGURATION OF AN ETHANOL PRODUCTION FACILITY WITH CARBON CAPTURE AND CO-LOCATED STORAGE





1. Initial capital is made available to the ProjectCo from investors.
2. This includes tax equity investors who are essentially buying the 45Q tax credits.
3. Once operational, the capture facility receives CO_2 from the ethanol production facility and stores it within the permitted geologic storage location onsite and the ethanol facility generates LCFS credits from its capture efforts.
4. LCFS credits can be sold at market rates and receive LCFS revenues, a portion of which is contributed to the ProjectCo.
5. A portion of earnings resulting from the LCFS credit sale may eventually be transferred to investors in the form of a dividend (cash distribution).
6. Since tax equity investors are only obliged to contribute 50 percent of the cost of 45Q tax credits upfront, there will be ongoing investments through the lifecycle of the capture operation.

Positive cash flow (for duration of LCFS, assumed 15 years) indicates ethanol with CCS is an investable project. *Source: Energy Futures Initiative and Stanford University, 2020.*

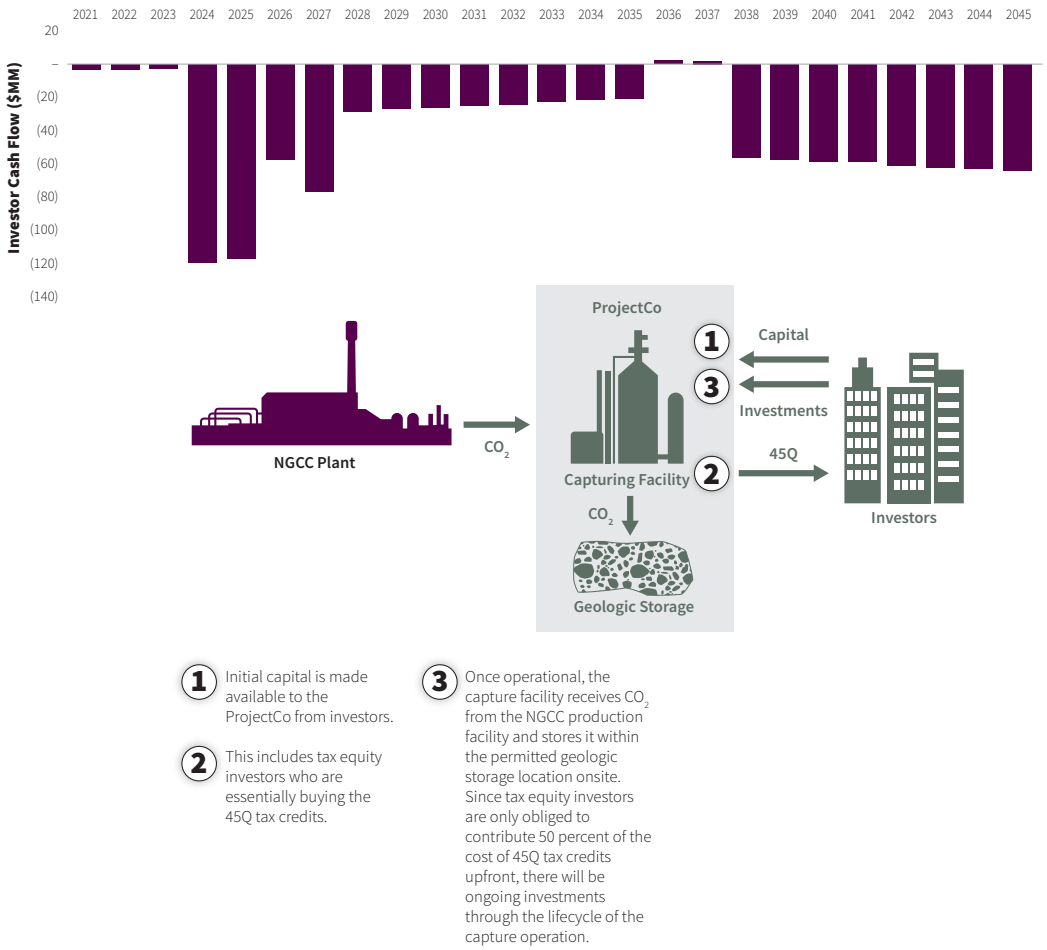
Case #2. NGCC Electricity Generation with Co-located Geologic Storage

A notional business configuration of an NGCC electricity generation facility with carbon capture and co-located storage is illustrated in Figure 3-16. In this case, the capture facility, along with any gathering pipeline and the storage infrastructure, is managed by ProjectCo, and the NGCC generation facility owner(s) have a majority equity stake.

Under current cost and support regimes, an investor would see net negative cash flows in almost every year of the project. Without a material and sustained source of revenue, such as Cap-and-Trade credits (which would be needed at a >\$60/tCO_2 value), there are no incentives for investing in NGCCs with CCS. This challenge is discussed in detail in Chapter 4.

FIGURE 3-16

GENERAL BUSINESS CONFIGURATION OF NGCC GENERATION FACILITY WITH CARBON CAPTURE AND CO-LOCATED STORAGE



Under current cost and support regimes, an investor would see net negative cash flows in almost every year of the project; this is not an investable project. *Source: Energy Futures Initiative and Stanford University, 2020.*

Case #3. Petroleum Refinery Hub (Hydrogen Production, CHP, FCCU) with Offsite Geologic Storage

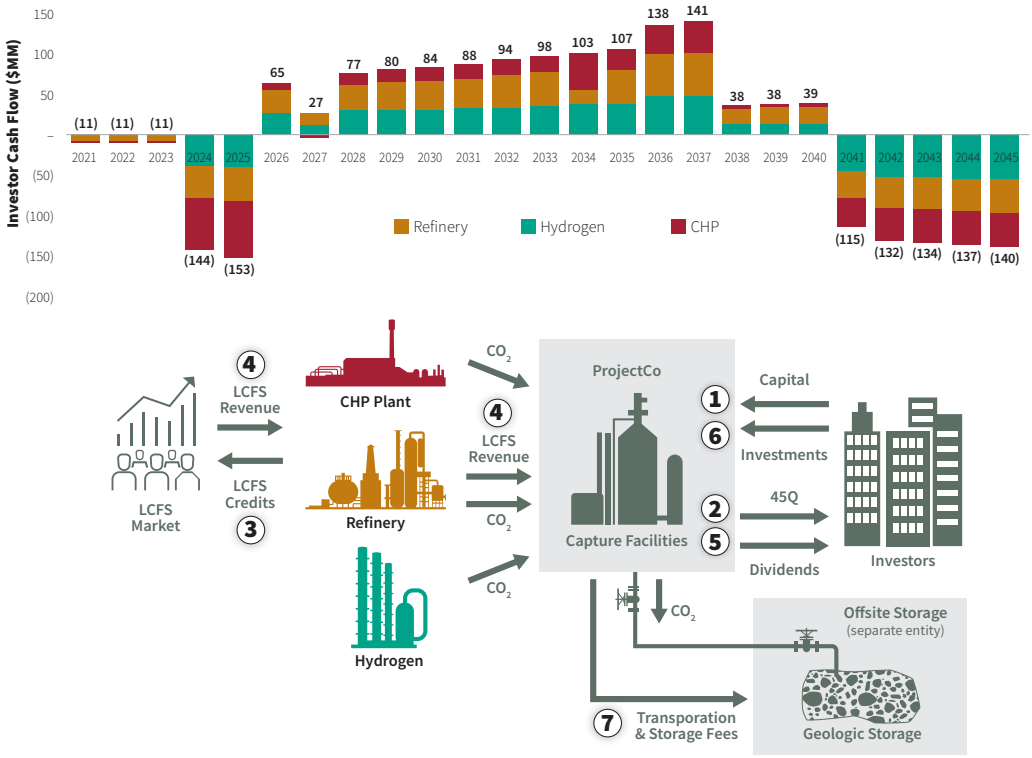
The general business configuration of a petroleum refinery hub (hydrogen, CHP, and FCCU) with carbon capture and offsite storage is illustrated in Figure 3-17. The refining hub consists of a hydrogen production facility, a CHP plant, and the refinery itself (FCCU) with carbon capture facilities (multiple) and offsite storage. The capture facilities (one per CO_2 source) are placed within the ProjectCo with the refinery owner(s) presumed to have a majority equity stake. The pipeline and storage infrastructure is owned/operated by entities other than the refinery plant owner(s).

It is assumed that the pipeline and storage infrastructure will be financed separately, and the returns will come from the storage and transportation fees.

In this case, the hub model achieves an IRR >15 percent and positive NPV and is an investable candidate project. Beyond the eligibility of this kind of project to produce and sell LCFS credits, it also benefits from economies of scale regarding the FEED study, capital expenditure, operation and maintenance, and transportation and storage cost, compared to individual projects.

FIGURE 3-17

GENERAL BUSINESS CONFIGURATION OF A PETROLEUM REFINERY HUB WITH OFFSITE STORAGE



1. Initial capital is made available to the ProjectCo from investors.
2. This includes tax equity investors who are essentially buying the 45Q tax credits.
3. Once operational, the capture facilities generates LCFS credits from its capture efforts.
4. LCFS credits can be sold at market rates, a portion of which is contributed to the ProjectCo.
5. A portion of earnings resulting from the LCFS credit sale may eventually be transferred to investors in the form of a dividend (cash distribution).
6. Since tax equity investors are only obliged to contribute 50 percent of the cost of 45Q tax credits upfront, there will be ongoing investments through the lifecycle of the capture operation.
7. CO_2 transportation and storage are contracted services, for which the ProjectCo enters into a typical "take-or-pay" arrangement with other infrastructure suppliers.

Positive cash flows (for duration of LCFS, assumed 15 years) indicate a refinery hub with CCS is an investable project. *Source: Energy Futures Initiative and Stanford University, 2020.*

Financial Model Insights

In line with the broader technoeconomic analysis in this study, a financial examination of these three project examples highlights that NGCC paired with CCS would not be a candidate for private developer investment absent additional support and incentives. This is due to a combination of insufficient sources of revenue, coupled with moderate to high costs of capture. In contrast, ethanol facilities—benefiting from the twin support mechanisms of 45Q and LCFS, and a relatively low cost of capture—could be attractive to investors. Another configuration benefiting from LCFS and 45Q revenue streams is the refinery hub model, which may be attractive to developers. Hubs offer 'economy of effort' where FEED, permitting and construction activities could be economized given the co-location of CO_2 emission sources.

Finally, project returns—irrespective of source and depending on quantity of captured CO_2 and distance traveled—may be enhanced if instead of individual onsite storage facilities, CO_2 is transported to a centralized storage facility that manage flows from multiple sources. The cost of the financial responsibility bond associated with each UIC Class VI well could be spread across multiple emission sources, reducing the up-front cost of individual projects. Moreover, this would also have the effect of changing the cost type from effectively a capital expense to an operational expense, thereby taking advantage of the time value of money.

Hubs offer 'economy of effort,' where FEED, permitting and construction activities could be economized given the co-location of CO_2 emission sources... Project returns may also be enhanced with centralized storage facilities managing flows from multiple sources.

EMERGING TECHNOLOGY OPPORTUNITIES ENABLED BY CCS

Development of CCS infrastructure can also enable new industries, such as hydrogen production and DAC, both important technologies for CDR. Both technologies may rely on geologic storage and projects using these technologies could take advantage of pipeline infrastructure that is built to handle point source emissions.

Hydrogen

Hydrogen is a clean energy carrier that could play multiple roles in achieving California's emission reduction targets, including for power generation and grid-scale energy storage, transportation (especially for heavy duty trucking), and as a clean feedstock for industry.

Driven by deep decarbonization goals, the number of countries that directly support investment in hydrogen is rapidly increasing. Governments in Asia and Europe have now invested more than $2 billion each year in hydrogen systems.[81] Globally, there are more than 50 targets, mandates, and policy incentives in place today that directly support hydrogen, including California's ZEV targets.[82]

According to the IEA, about 97 percent of hydrogen produced today comes from fossil fuels using a process called steam methane reforming (SMR).[83] The two prominent clean pathways for making hydrogen are SMR plus CCS or producing hydrogen via electrolysis powered by low- or no-carbon resources. California's abundant renewable energy resource potential and its considerable capacity for geologic storage of CO_2 make it well suited for the development of clean hydrogen infrastructure by both means. Table 3-4 details cost and capacity information for various hydrogen production methods as determined by the National Renewable Energy Laboratory (NREL) Hydrogen Analysis (H2A) team;[84] currently, utilizing CCS with SMR can produce clean hydrogen at a much lower cost and far greater volumes than through electrolysis using renewable energy.

TABLE 3-4

SURVEY OF COST ESTIMATES FOR HYDROGEN PRODUCTION

Description	Capacity (tons/day)	Hydrogen Production Cost[r,s] ($/kilogram)	Major assumptions ($/kilowatt)	Comments
Electrolytic Hydrogen				
H2A centralized electrolysis[85]	50	4.5-5.2	Electrolyzer CAPEX: $641-1460/kW	Electricity sourced from the grid
H2A distributed electrolysis[86]	1.5	4.5-5.2	Electrolyzer CAPEX: $714-1486/kW	Electricity sourced from the grid
Central electrolysis with wind[87]	52	4.3	Electrolyzer CAPEX: ~$2000/kW	Electricity sourced from the grid. Wind power credits purchase assumed
Co-located Wind electrolysis[88]	50	2.8-12.2	Electrolyzer CAPEX: $400/kW; Wind CAPEX: $1571-2356/kW	Grid electricity used to manage variability in wind generation; excess wind power sold to grid.
PV electrolysis: grid assisted vs. PV only[89]	10	6-12.1	Electrolyzer CAPEX: ~$900/kW	Lower cost with grid + PV electricity; electrolyzer capacity factor with PV only ~20 percent
SMR with CCS[90]				
Centralized NG reforming - SMR	380	1.10-1.15	NG price ($/MMBtu) 3.73	
Centralized NG reforming -SMR with CCS	380	1.52-1.56		
Distributed NG reforming	1.5	1.40-1.50		

This table details cost and capacity information for various hydrogen production methods. *Source: Compiled using data cited within the table.*

According to one study, by 2030, the hydrogen economy in the U.S. could generate an estimated $140 billion per year in revenue and support 700,000 total jobs across the hydrogen value chain; by 2050, the hydrogen economy could generate $750 billion per year in revenue and support a cumulative 3.4 million jobs.[91] California can play a leadership role in this rapidly expanding market to create jobs, support economic growth, and strengthen its leadership in decarbonization.

In California's transportation sector, low and zero emissions transportation options will drive decarbonization, especially in light of Governor Newsom's executive order issued September 23, 2020 that requires new passenger cars and trucks to be zero-emission by 2035, and all medium and heavy duty vehicles to be zero-emission by 2045.[92] Although battery electric vehicles (BEVs) currently represent most of the ZEVs on the road in California, fuel cell electric vehicles offer many desirable features, including longer range, higher payload, greater cargo volume, and fast refueling.[93] These qualities are particularly important for heavy duty vehicles, which accounted for 34 MtCO2 of emissions in 2017.[94] California's current hydrogen infrastructure, consisting of 48 fuel cell buses and 42 hydrogen fueling stations as of September 2020, is expected to experience significant growth, with 15

r Costs are as-reported in each of the analyses and do not reflect any adjustments to facilitate comparison (e.g. common base year).

s To the extent possible, cost of hydrogen delivered has been subtracted to report only the production cost estimates.

additional fueling stations and seven new buses currently in development.[95]

In the industrial sector, hydrogen is used as a feedstock, most notably in the refining industry and in the production of fertilizers and chemicals. As industrial demand continues to grow, it will be critical to decarbonize these feedstocks. Almost all the hydrogen used as industry feedstock is currently produced onsite in dedicated plants or as a by-product from other processes.[96] This analysis found that installing carbon capture on existing hydrogen production has the potential to abate approximately 10.1 $MtCO_2$/yr as shown in Table 3-1 above.

Hydrogen can also support decarbonization of the power sector by providing an innovative clean firm generation option and as an energy storage resource. Turbines fired with hydrogen or hydrogen carriers, such as ammonia, can provide increased flexibility to the grid, an especially important feature as intermittent renewable resources increase. Power plants producing power during off-peak hours can produce hydrogen, which can be stored over a long period of time and used by the hydrogen-fired generators during periods of peak demand or low availability of intermittent resources.

Direct Air Capture

DAC technologies remove CO_2 directly from the atmosphere.[97] Although DAC has a large theoretical potential for CO_2 removal, it must be coupled with a disposition pathway, such as CO_2 utilization or geologic storage, to constitute a complete carbon removal system.[98] DAC can be co-located with suitable storage or utilization sites, eliminating the need for long-distance CO_2 transport. Depending on the specific DAC technology employed, land and water footprints may be relatively limited.[99,100] California is well suited to develop DAC facilities supported by geologic storage.

DAC is in the early commercial stage of development. Two technology approaches are being used to capture CO_2 from ambient air. Liquid systems pass air through chemical solutions (e.g. a hydroxide solution), while solid systems use solid sorbent filters to chemically bind with CO_2. There are currently 15 DAC plants operating worldwide, capturing more than 9,000 tCO_2/year, with a one $MtCO_2$/yr capture plant in advanced development in the U.S.[101]

Many variables are involved in estimating the cost per ton abated by DAC. The National Academies of Sciences, Engineering, and Medicine reported that "estimates found in the literature span an order of magnitude, from \$100 to \$1,000/tCO_2.[102] Costs vary by the type of CO2 separation technology used, energy requirements and prices, and plant size, among others. Most publicly available cost estimates are literature-based system models as opposed to empirical evidence from system operations, as one study shows (Table 3-5).[103]

TABLE 3-5

ESTIMATED DAC COSTS AND ENERGY REQUIREMENTS BY TECHNOLOGY

	Unit	Solid DAC	Liquid DAC (electrified)
CAPEX	\$/tCO2	855	954
OPEX	% of CAPEX	4	3.7
Electricity	kWh_e/tCO_2	250	1,535
Heat	kWh_{th}/tCO_2	1,750	n/a

These data on cost and energy requirements for DAC technologies are based on a review of the literature. Costs were converted from Euros to Dollars using the conversion rate of 1:1.18. *Source: Energy Futures Initiative and Stanford University, 2020. Compiled using data from Fasiihi et al., 2019.*

Another bounding factor is the significant energy needs to separate CO_2 from ambient air, which is roughly 300 times more dilute than in flue gas streams.[104] The energy requirements also vary by DAC technology. One study estimates them to range from between 250-1,535 kilowatt-hour (kWh) of electricity per tCO_2 removed and an estimated 1,750 kWh of thermal energy per ton of CO_2 removed for the solid state DAC technology.[105]

THE OPPORTUNITIES ARE REAL BUT SO ARE THE CHALLENGES

As noted in Chapter 1, it will be very difficult for the state to meet its 2030 emissions reduction targets in the power and industrial sectors without CCS. This chapter has laid out the opportunity:

- Identification of emissions sources that could be retrofit for CCS and abate nearly 60 $MtCO_2$/yr;
- Identification of 70 Gt of CO_2 storage potential in the state; and
- Identification of project and transportation infrastructure options.

This chapter also highlighted the potential benefits of CCS to local communities and the enabling benefits of CCS to drive new technologies, such as hydrogen and DAC. However, California's current policy and regulatory environment present challenges that may make this opportunity difficult to achieve. Chapter 4 "Challenges for CCS in California" lays out the findings from numerous stakeholder interviews, and discusses that barriers facing CCS in the state today.

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Chapter 4

Challenges to CCS Project Development in California

California can deploy CCS in the near-term to abate nearly 60 $MtCO_2$/yr, approximately 15 percent of the state's current emissions levels. However, there are no operating CCS projects in California. Projects currently under development will provide valuable lessons learned for future efforts. Informed by interviews with project developers, financiers, and industry stakeholders, as well as archival research and analysis of California's policy landscape, this chapter describes the existing barriers to widespread CCS deployment.

KEY FINDINGS

- The biggest challenges to CCS project development identified through interviews with CCS project developers, industry associations, and financiers included: 1) the state's position on the future role of CCS is ambiguous; 2) the regulatory process for CCS is complex and untested; 3) project revenues and costs are uncertain; and 4) the public's awareness of CCS is lacking.
- CCS has received some state policy incentives—including eligibility under the LCFS—but it is not eligible under Cap-and-Trade and is not currently included in the analysis for SB100, the CPUC's Integrated Resource Plan (IRP), and the CEC's Integrated Energy Policy Report (IEPR).
- CCS project permitting is a significant undertaking, as agencies involved may not be familiar with CCS and clear on its role, developers may not be familiar with the myriad of permits required for a complex CCS project, and the timelines for certain key permitting steps—namely the CEQA review and the UIC Class VI application—are uncertain and lengthy.
- From a revenue perspective, two policy support mechanisms—the LCFS and 45Q—provide cash flows that could justify the capital and operational expenses needed to design, build, and operate the necessary property, plant and equipment for CCS. Uncertainties about the length of time these incentives will be available, however, and their sustained dollar value—especially the LCFS—dampen developer and investor interest in CCS in California.
- Public acceptance is a cross-cutting issue, potentially affecting each category of challenges described in this chapter. CCS is unknown to many in the general public, and among those who are familiar with the technology, public attitudes are wide ranging and highly variable. Public acceptance, built on understanding the process, risks, and opportunities, is important since public attitudes could make or break a CCS project.
- Many of the identified barriers to CCS development in California could be minimized by administrative adjustments and policy clarifications, as opposed to policy streamlining and/or legislative actions.

Despite the potential for CCS to make meaningful and cost-effective contributions to mitigating California's GHG emissions, there are many challenges for project developers and investors. For now, CCS is primarily a pollution abatement technology for existing industries that do not have other options for reducing emissions at the scale and pace needed to meet California's climate goals.

In some respects, adding carbon capture to an industrial facility or power plant is not unlike other pollution abatement technologies, although the transportation and storage requirements for CCS add both cost and complexity to the mitigation of carbon pollution. The key questions remain, however: who pays for the cost increases and how are these costs both mitigated and managed?

Government subsidies (e.g. tax credits) have been used to help offset some, or all, of the costs during the transition period. Subsidies are particularly helpful in the early stages of a transition for de-risking technologies, building supply chains sufficient to scale the industry, and encouraging early actors to engage. Incentives are also extremely important. The solar and wind industry, for example, benefited from a combination of incentives, such as the federal government's Production and Investment Tax Credits, California's mandated RPS, and direct consumer incentives for distributed generation. The battery storage industry got a boost from the state's Energy Storage Procurement Mandate.[1]

In addition, the creation of market-based regulations, e.g., Cap-and-Trade and LCFS, achieves key policy goals. Also, in the event that a federal carbon tax was to be implemented, CCS costs would, at a minimum, be weighed against the costs of the alternative technologies that offer comparable emissions reductions, as well as against their systems value and limitations, e.g. firm power versus limited duration storage.

How the added cost of pollution abatement is managed and how costs are allocated can have profound impacts on consumers, on industry, the jobs it supports, adoption of innovation technologies, and the economy in general. The transition risks are particularly acute during times of technology and policy changes, when different actors adopt new technologies at different rates, disparate economic sectors have varying abilities to cope with the added costs and operating complexities, and certain businesses can simply choose to shut down or move their business to other states.

While carbon capture should be considered a pollution abatement technology (the Supreme Court found that carbon emissions are a pollutant covered by the Clean Air Act),[2] CCS has, as noted, unique characteristics that make it more complicated. CCS requires that large amounts of captured CO_2 be disposed of both permanently and safely, although at some point in time, CO_2 may have value as a commodity. To put this storage requirement in perspective, the 59 $MtCO_2$/yr from sources identified in this study as promising for CCS, has a volume that is 75 percent greater than all of the solid wastes that are put in landfills every year in California.[a,3] Unlike other pollution abatement industries where the volumes of waste that are produced are relatively small, effectively managing the large volume of CO_2 is central to the success of—and challenges for—CCS.

Effective policy measures for scaling the technologies and infrastructure needed for this valuable emission reduction option will require addressing three key challenges: dealing with the added costs from CO_2 capture; building the infrastructure for managing the captured CO_2; and gaining public acceptance. The combination of these challenges for deploying and scaling CCS creates both a high degree of uncertainty for prospective developers and investors, and complexity regarding financing, regulatory compliance, and license to operate. Finding the right combination of incentives and mandates for CCS is key to the successful adoption of new pollution reduction technologies, sustained economic output, a reliable grid, and the transition to a net-zero carbon economy.

The combination of these challenges for deploying and scaling CCS creates both a high degree of uncertainty for prospective developers and investors, and complexity regarding financing, regulatory compliance, and license to operate.

a California landfills 37.8 Mt of solid waste every year.

STAKEHOLDER PERSPECTIVES ON CCS IN CALIFORNIA

As noted, there are state and federal policies that offer considerable financial support to CCS development:

- The 45Q tax credits, revised in 2018, provide \$50/tCO_2 for geologic storage by 2026.
- California's LCFS, with credits currently trading around \$200/tCO_2.

In recent months, these incentives have generated a great deal of interest on the part of developers, tax-equity investors, and those industries standing to gain financially from CCS development. There are, however, no CCS projects deployed in California to date. This chapter discusses the challenges facing would-be CCS project developers and key stakeholders in California and the limitations of policies meant to incentivize those projects.

The analysis in this chapter is informed by interviews with project developers, financiers, and industry stakeholders, as well as archival research and analysis of California's policy landscape. More than 30 CCS project developers, industry associations, and financiers were interviewed on their perceived challenges of developing CCS projects in California (Table 4-1 and see Appendix D for interview methodology).[b] In some cases, the issues they identified are unique to California; others are common to CCS project developers in the U.S. and around the world.

TABLE 4-1

SUMMARY OF INTERVIEWS CONDUCTED FOR ANALYSIS

	Stakeholder			
Industry	**Analyst/ Industry Association**	**Investor**	**Project Developer**	**Total**
Cement	3			**3**
Chemicals			3	**3**
Diversified Energy	2		13	**15**
Environmental Advocacy	1			**1**
Infrastructure	3	3	2	**8**
Investment & Financial Services		3		**3**
Power			6	**6**
Private Equity		2		**2**
Public Sector	3			**3**
Refinery			5	**5**
Reinsurance	2			**2**
Utility			2	**2**
Total	**14**	**8**	**31**	**53**

More than 50 interviews with CCS project developers, industry associations, and financiers were conducted to identify perceived challenges of developing CCS projects in California. Note that these values are lower bounds on the number of individual interviewees, as some interviews had multiple participants/interviewees from a given stakeholder firm/organization. *Source: Energy Futures Initiative and Stanford University, 2020.*

b In addition to stakeholder interviews, the external project Advisory Board provided significant insight and input and includes representatives from environmental NGOs, think tanks, labor unions, academia/research, and industry, as well as former government officials.

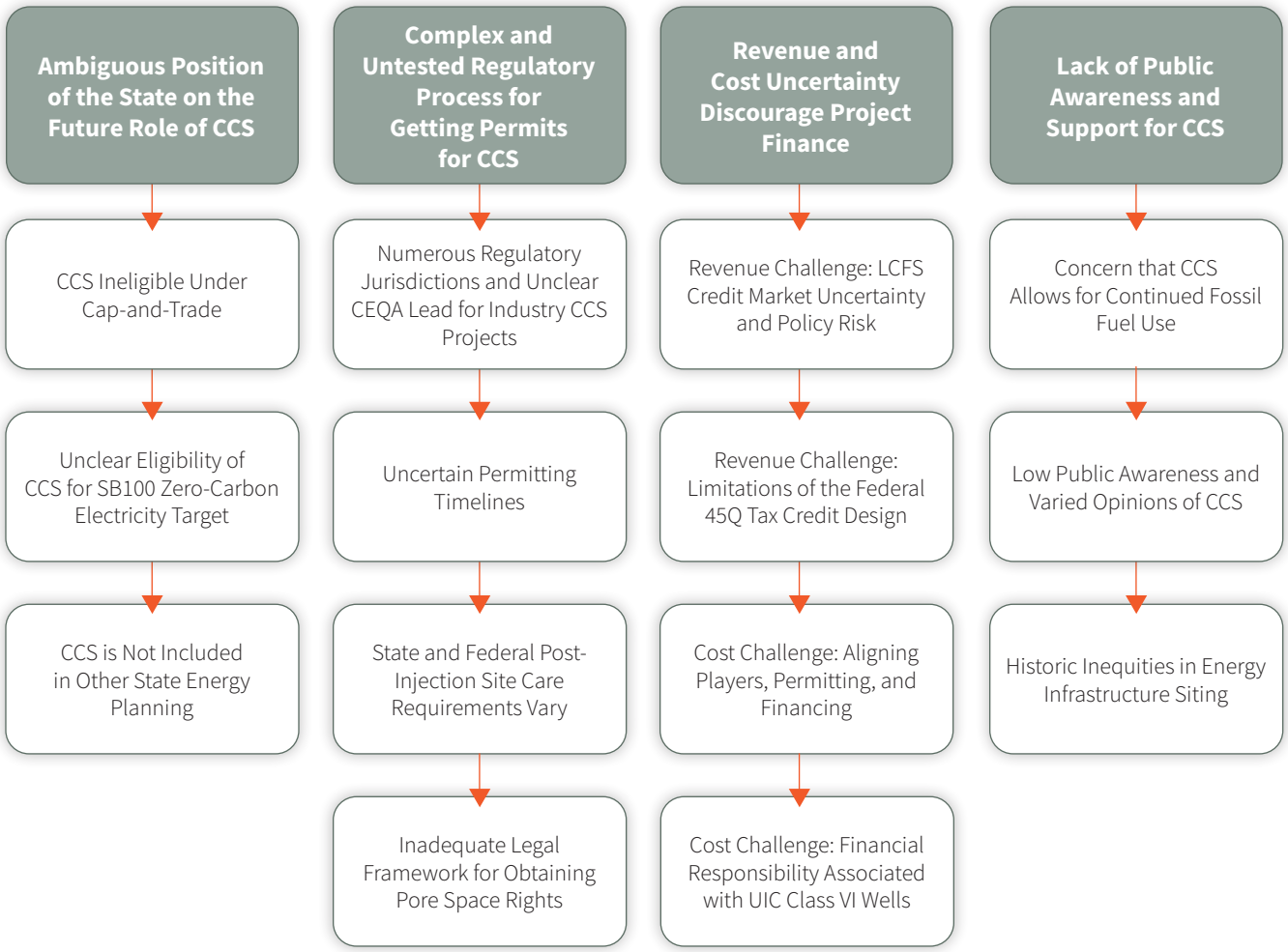
The major challenges facing CCS projects in California are shown in Figure 4-1 and can be grouped into four categories:

- Ambiguous position of the state on the future role of CCS;
- Complex and untested regulatory process for getting permits for CCS;
- Revenue and cost uncertainty discourage project finance; and
- Lack of public awareness and support for CCS.

These are discussed in detail in the following sections of this chapter.

FIGURE 4-1

SUMMARY OF CHALLENGES FOR CCS PROJECT DEVELOPMENT



This analysis identified key challenges for CCS project development in California through interviews with project developers, financiers, and industry stakeholders, as well as archival research and analysis of California's policy landscape. *Source: Energy Futures Initiative and Stanford University, 2020.*

AMBIGUOUS POSITION OF THE STATE ON THE FUTURE ROLE OF CCS

A stable and consistent policy environment is critical for developing and deploying GHG mitigation technologies at scale. In this regard, California has a strong and successful track record of creating policy frameworks, including several mandates, that have ushered in a whole new generation of energy technologies. Examples of successful policy measures include RPS goals, building and appliance energy efficiency standards, and most recently, the energy storage procurement mandate.[4] Absent a clear and enduring indication of policy support for CCS, project developers will turn their attention to other areas in which to invest.

CCS is a relatively mature clean energy technology that helps enable clean firm power and sustain the economic value of the state's industrial sector, which is difficult to decarbonize and at the same time, is responsible for 36 percent[5,c] of California's gross state product. It has the potential to reduce nearly 60 $MtCO_2$/yr, approximately 15 percent of the state's 2017 GHG emissions, with the potential for larger reductions depending on, for example, capacity factors of NGCCs and growth in the industrial sector.

To put this in perspective, California's buildings sector was responsible for around 9.7 percent of the state's overall emissions in 2017; this level, with massive efficiency programs, could likely be cut in half. Policies are being promulgated to support building electrification that will require new generation, transmission, and distribution infrastructure and the stranding of existing infrastructure to further reduce emissions from buildings. In spite of its potential to deliver significant emission reductions that could exceed those from an electrified buildings sector, CCS is unlikely to become part of California's clean energy technology portfolio in the future absent additional recognition and policy support from the state.

CCS has received some state policy incentives—namely eligibility under the LCFS—but it is not eligible under Cap-and-Trade and is not currently included in the analysis for SB100, the CPUC's Integrated Resource Plan (IRP), and the CEC's Integrated Energy Policy Report (IEPR). The state's strong support and leadership in energy efficiency, renewable energy, energy storage, and vehicle electrification paved the way to reducing emissions by more than 14 percent from their peak in 2004.[6] A similarly supportive environment could make California a leader in CCS and CDR as well.

In spite of its potential to deliver significant emission reductions that could dwarf those from an electrified buildings sector, CCS is unlikely to become part of California's clean energy technology portfolio in the future absent additional recognition and policy support from the state.

CCS is Ineligible Under Cap-and-Trade

CARB established the Cap-and-Trade program in 2011 to reduce statewide emissions to 1990 levels by 2020. It requires that electricity generators and industrial sources of GHGs emitting more than 25,000 tCO_2e annually meet a declining emissions limit, or "cap." Regulated entities must either reduce emissions below the cap or retire allowances equal to the difference between their annual emissions and the annual cap. These allowances can be traded through a regulated market, creating a price on carbon for regulated emitters. Since 2014, California's market has been tied to Quebec's, with prices ranging from \$12.10 USD/tCO_2e in November 2014 to a peak of \$17.45 USD/tCO_2e in May 2019.[7] During the most recent auction in August 2020, the average settlement price was \$16.68 USD/tCO_2e.[8]

In 2010, CARB issued Resolution 10-42 ordering the creation of "a public process to establish a protocol for accounting for sequestration of CO_2 through geologic means and recommendations for how such sequestration should be addressed in the Cap-and-Trade program."[9] A decade later, CARB has still not adopted a CCS Protocol for the Cap-and-Trade program, and CCS is not recognized as a pathway for directly reducing the regulatory compliance of emitters. Even if a covered emitter captures and stores

c "Percentage calculated from economic subsectors identified in U.S. Bureau of Economic Analysis (BEA) statistics which align with CARB's GHG inventory classifications for industry, as a fraction of the total economic product determined by BEA."

its CO_2 emissions, CARB still considers those CO_2 emissions to be emitted and requires the covered emitter to meet its compliance obligation (by either retiring emissions allowances or purchasing permits or offsets) for those emissions as if they were unabated. Covered entities have no financial or regulatory incentive under Cap-and-Trade to deploy CCS, and, in fact have a *disincentive* for doing so since CCS is not recognized as an abatement pathway.

Covered entities have no financial or regulatory incentive under Cap-and-Trade to deploy CCS, and, in fact have a disincentive for doing so since CCS is not recognized as an abatement pathway.

Given the absence of a CCS Protocol, California's Cap-and-Trade program provides no policy support for verifiable emissions reductions via CCS from key emitting industries such as cement (7.8 $MtCO_2e$ in 2018), non-oil and gas combined heat and power plants (10.1 $MtCO_2e$ in 2018), and NGCC power plants (27.5 $MtCO_2e$ in 2018)[d]. Combined emissions from these sources are 11 percent of California's annual emissions in 2017 (424 $MtCO_2e$).[10]

Unclear Eligibility of CCS for SB100 Zero-Carbon Electricity Target

California passed SB 100 in 2018, increasing the state's RPS goal to 60 percent renewables by the end of 2030. It also mandated that "…eligible renewable energy resources and zero-carbon resources…" supply all retail sales and state electricity purchases by the end of 2045.[11]

Analysis detailed in Chapter 3 shows that having NGCC-CCS could lower the costs of decarbonizing the power sector aligned with the state's 2030 economywide emission reduction target.[e,12] Despite this potential, it remains unclear if NGCC-CCS qualifies under the definition of "eligible zero-carbon resources" under SB100. Several organizations have suggested that CCS (either directly at power plants or used in the production of "fuels" like hydrogen) could be an eligible zero-carbon resource,[13] while others interpret the SB100 legislative language to exclude CCS.[14]

The CEC, CARB, and CPUC have been developing an SB100 Joint Agency Report, as required by statute, that reviews the technologies, forecasts, transmission, safety, affordability, and reliability considerations associated with achieving the 100 percent zero-carbon resources goal. This process includes the modeling of alternative scenarios for achieving SB100's policy objectives. At a technical workshop in November 2019, CARB proposed two alternative definitions of eligible electricity resources: one that included natural gas with CCS that captured all emissions; and another that excluded combustion-based technologies.[15] The SB100 Draft Results presented September 2, 2020 excluded natural gas with CCS as a candidate resource "due to insufficient cost data."[16] The CEC is currently accepting comments on these draft modelling results, including from many stakeholders who argue that CCS should be included as a candidate technology and that costs are sufficiently known to be included in capacity expansion modelling being undertaken by the CEC.

CCS is Not Included in Other State Energy Planning

CCS has also not been included in the analysis for California's IRP process. The IRP was established in 2015 with the passage of SB350, and set targets for the state's 2030 power sector of 50 percent renewable energy procurement, the doubling of energy efficiency, and promotion of transportation electrification.[17] The IRP process is overseen by the CPUC, in consultation with CARB and the CEC, and the goal of the IRP document is to outline how load-serving entities will meet demand, provide reliable, affordable electricity, and meet the emission reductions and RPS targets set first by SB350 and increased by SB100.[18] CCS was not considered as a resource in the 2017-2018 IRP plan, though there were still 23-25 GW of unabated natural gas resources included in the modeling for 2030.[19]

d Estimates based on technoeconomic analysis conducted for this study; detailed fully in Chapter 3.

e The SB100 policy establishes a 60 percent RPS by 2030 goal, but California currently does not have an explicit emissions goal for the electricity sector in 2030. An analysis titled Deep Decarbonization in a High Renewable Future commissioned by the CEC allocates 32 MtCO2/yr as a carbon budget to meet California's economywide carbon reductions goal set in SB32.

CCS is discussed briefly in the CEC's 2019 IEPR, which is a biennial assessment of the "trends and issues facing California's electricity, natural gas, and transportation fuel sectors."[20] The goals of the IEPR are to inform ways of conserving resources; protecting the environment; ensuring reliable, secure, and diverse energy supplies; enhancing the state's economy; and protecting public health and safety.[21] Required by SB1389 in 2002, the IEPR has been an important resource for policymakers to comprehensively assess energy issues in a transparent, inclusive, and multi-sectoral way. The IEPR process considers external research and analysis of California's decarbonization targets, energy trends, and pathways to achieve its goals and provides an opportunity for experts and stakeholders to contribute to workshops and forums. The 2019 IEPR states that "for the near term, natural gas generation will continue to play an important role in integrating renewable resources and ensuring reliability."[22] Discussions of carbon capture are, however, limited to summaries of public commentary on the technology, and there is no analysis of the potential role of NGCC-CCS in this report, despite the acknowledgement that gas will continue to play an essential role in grid reliability.

COMPLEX AND UNTESTED REGULATORY PROCESS FOR GETTING PERMITS FOR CCS

As with many new clean energy technologies, aspects of development and permitting processes at the state, local, and federal levels are initially unclear or unknown, while others are untested in practice. This increases the difficulty of raising the financing needed to move a conceptual CCS plan into the investment-ready project phase.

As noted, no two CCS projects are the same; they each have different permutations (i.e. with or without pipelines and within one or numerous jurisdictions). Every CCS project is also unique from a planning and permitting perspective since the exact location and project type (i.e. electricity or industrial sector) will impact what permits are necessary and which local, state, regional, and/or federal agencies would be involved. In addition, since California currently does not have any projects, the permitting landscape is relatively untested, with uncertain timelines and numerous entities potentially involved. An overview of the permitting requirements was provided in Chapter 2 and Appendix A; this section discusses permitting and regulatory challenges.

The 2019 IEPR states that "for the near term, natural gas generation will continue to play an important role in integrating renewable resources and ensuring reliability." Discussions of carbon capture are, however, limited.

Numerous Regulatory Jurisdictions and Unclear CEQA Lead for Industry CCS Projects

The entire CCS process, from CO_2 capture to storage, involves complicated equipment, multiple actors, and a multitude of process steps. The permitting of CCS projects can be a significant undertaking, as agencies involved may not be familiar with CCS; developers may not be familiar with the myriad of permits required for a complex CCS project; and the timelines for certain key permitting steps—namely the CEQA review and the UIC Class VI application—are uncertain and lengthy. As discussed in Chapter 2, permitting for CCS for electricity generators is likely to be less uncertain than for industry because the CEC has exclusive jurisdiction over thermal power plants; the industrial subsectors with CCS potential have no such permitting lead.

This lack of a clear lead regulatory entity for industry is particularly noteworthy, as the environmental review process under CEQA requires a singular "lead agency" to oversee the process. Specifically, CEQA Guidelines clarify that, "where a project is to be carried out or approved by more than one public agency, one public agency shall be responsible for preparing an Environmental Impact Report (EIR) or Negative Declaration (ND) for the project."[23] The CEC serves as the CEQA lead for thermal power plants; determining a lead for industrial CCS projects, however, would be difficult. According to CEQA, "the lead agency will normally be the agency with general governmental powers, such as a city or county, rather than an agency with a single or limited purpose such as an air pollution control district or a district that will provide a public service or public utility to the project."[24] Some local governments may require additional resources to permit a private project as complex as CCS and may lack general expertise in the technology. [f,25]

Permitting CCS projects can be a significant undertaking, as agencies involved may not be familiar with CCS; developers may not be familiar with the myriad of permits required for a complex CCS project; and the timelines for certain key permitting steps—namely the CEQA review and the UIC Class VI application—are uncertain and potentially lengthy.

The two fundamental permits for a CCS project are the EPA UIC well permit: either Class VI for deep saline reservoir storage or Class II for EOR; as well as the Authority to Construct and Permit to Operate (ATC/PTO) permits under the CAA. Class VI wells in California remain under the permitting authority of EPA Region 9. Class II wells, on the other hand, are permitted by CalGEM, as the state received primacy, or primary enforcement responsibility,[26] from the EPA in 1983.[27] The ATC/PTO falls under the CEC's exclusive jurisdiction for natural gas power plants, while for industry, permits are reviewed by the local air boards.

A summary of the jurisdictional responsibilities of agencies potentially involved in CCS permitting is detailed in Table 4-2.[28] Because there is limited experience with large-scale CCS projects in California, it is unclear to the project developers and sometimes even to the agencies themselves where the jurisdictional lines fall, especially for more complex projects involving pipeline transportation. These circumstances can directly or indirectly increase project risks and drive up costs.

f For example, if a city or county does not include energy and/or air quality in its general plan (which expresses a city or county's development goals relative to the distribution of future land uses) , it may not be legally able to permit a CCS project. Additional detail can be found in Appendix A.

TABLE 4-2

REGULATORY OVERSIGHT FOR CCS RETROFIT PROJECTS IN CALIFORNIA

Agency	Requirement or Authority	Possible Value Chain Segments
California Energy Commission	Exclusive jurisdiction over thermal power plants 50 MW or greater in size	Capture, Transport, Storage
California Geologic Energy Management Agency	UIC permitting for Class II (EOR) wells	Storage
California Public Utilities Commission	Public utility regulation over multi-user pipelines	Transport
State Fire Marshal	Operational oversight over "hazardous liquid" pipelines[29]	Intrastate Transport
California Department of Fish and Wildlife	California Endangered Species Act permitting and Lake and Streambed Alteration	Transport, Storage
California Coastal Commission	California Coastal Development Permit (CDP)	Capture, Transport, Storage
Regional Water Boards	Waste Discharge Requirements and National Pollutant Discharge Eliminate System (NPDES) permits	Capture, Transport, Storage
Local Air Districts	Air quality permitting under state and federal Clean Air Acts and local rules	Capture
Local City and County Governments	Local land use planning and permitting	Capture, Transport, Storage
U.S. Environmental Protection Agency, Region 9	Prevention of Significant Deterioration (PSD) permit modifications	Capture
	UIC permitting for Class VI (permanent geologic storage) wells	Storage
U.S. Department of Transportation	Operational oversight over "hazardous liquid" and CO_2 pipelines	Interstate Transport
U.S. Department of Fish and Wildlife	Endangered Species Act consultation and permitting	Transport, Storage
U.S. Bureau of Land Management	Right of way issuance over federal lands managed by the Bureau of Land Management	Transport
U.S. Army Corps of Engineers	Clean Water Act Section 404 permitting for discharge of dredged or fill materials into U.S. waters	Transport, Storage

This table details the various agencies that potentially have regulatory oversight over certain aspects of a CCS project. *Source: Energy Futures Initiative and Stanford University, 2020. Adapted from Calpine/Covington and Burling.*

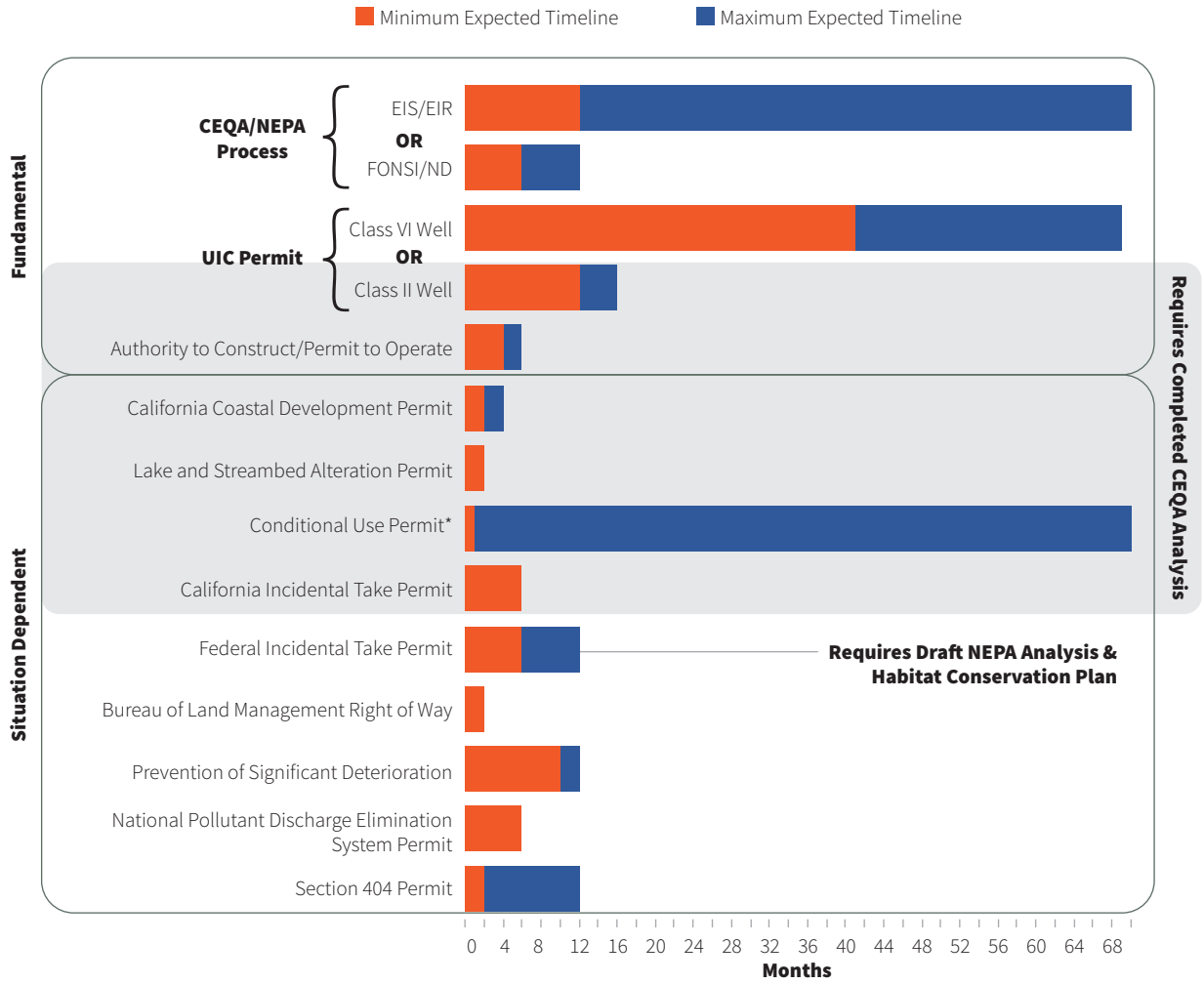
In addition, there are tribal governments and local governments and agencies that would likely have a role in CCS permitting. To the extent any aspect of a CCS project might fall under tribal jurisdiction or in or around a geographic area traditionally or culturally affiliated with a Native American tribe, consultation with tribal governments would be needed.[30] Local government agencies could include, the California County Board of Supervisors; the County Roads Department; the County Department of Engineering; the County Environmental Health Services Department; the County Planning Department; the local water agency; and the local fire department.[31]

Uncertain Permitting Timelines

As described in Chapter 2, CCS projects require at least three fundamental permits from different regulatory processes: ATC/PTO; either a Class VI or Class II well permit; and either a CEQA or a joint CEQA/NEPA review. The notional permitting timelines depicted in Figure 4-2 show two key permits that will impact the total permitting timeframe: the Class VI well application and the CEQA process. It is notable that both the ATC/PTO permits and the well permits require the CEQA (as well as NEPA, when required) process to be completed for a project to commence. The other permits shown in the lower box in Figure 4-2 may or may not be required depending on the specific project circumstances.

FIGURE 4-2

ESTIMATED CCS PROJECT PERMITTING TIMELINES



This figure illustrates timelines of permitting processes that may be required to develop a CCS project in California. The timelines are notional estimates based on federal and state guidelines, project case studies, and agency reports. The orange bars are a minimum estimated permitting duration from application to permit issuance, while the blue bars indicate how long the process could potentially take. Blue bars that extend to the end of the graph represent processes that could have an indefinite timeframe. Permits shaded in grey require a completed CEQA (either an ND or EIR) to commence. *Source: Energy Futures Initiative and Stanford University, 2020.*

**Conditional Use Permits (CUPs) must be in accordance with the city or county's general plan (i.e. meet the development objectives) to be approved. General plans are not updated often, so this should be taken into careful consideration by a developer.[32] Typically, a CCS project would be located in an area zoned for industrial uses. However, pipelines and storage facilities may require a general plan amendment which would trigger CEQA.*

Projects pursuing Class VI wells in California would likely first submit the Class VI application to the EPA. Class VI well permitting is a relatively new and untested process, with only two Class VI wells permitted in the U.S.[33] The ICCS project (described in Chapter 2) is the first large-scale CCS project to receive a permit to inject under the Class VI program. This took nearly six years,[34] although the timeline will likely shorten as more projects apply for Class VI permits.

Class VI well permitting is a relatively new and untested process, with only two Class VI wells permitted in the U.S... In contrast, California has ample experience permitting Class II wells for EOR, as the state has over 55,000, the most Class II wells of any state.

In contrast, California has ample experience permitting Class II wells for EOR, as the state has over 55,000, the most Class II wells of any state.[35,g,36] Class II wells take approximately one year to permit in California.[37] The faster and more predictable timelines, coupled with the less costly application requirements of Class II wells, makes them more attractive than Class VI permits for CCS project developers, despite the climate benefits of storing CO_2, in deep saline reservoirs as opposed to using it for EOR.

The CEQA process is separate from, and must be completed prior to, other state and local permitting processes. CEQA has two main outcomes: if environmental impacts are reasonably expected from a proposed project, an EIR is required, which, generally takes at least one year, and in some instances, can take several years to complete.[38] Alternatively, an ND occurs when there are no significant environmental impacts associated with the project; this generally takes six months to a year.[39] In all cases, CEQA is a big determinant of a project's timeline as other state and local permits, such as the ATC/PTO, require either an ND or a completed EIR to commence. In addition, these timelines are often increased significantly for controversial projects– as early CCS projects might be – by litigation related to the adequacy of the EIR.

State and Federal Post-Injection Site Care Requirements Vary

The post-injection site care (PISC) requirements after a CO_2 injection well is capped are twice as long in the CCS Protocol under California's LCFS than the federal requirements for Class VI wells, posing additional costs and risks for project developers.

The EPA UIC regulations for Class VI wells have a default of 50 years of PISC responsibility after CO_2 injection wells have been capped.[40] States that achieve primacy for Class VI wells can implement shorter PISC timeframes if they can demonstrate that a shorter timeframe will not threaten the safety of underground sources of drinking water. In contrast, there are no PISC requirements for Class II wells at the state or federal level.[41] California has primacy for Class II wells, which are overseen by CalGEM, and the statute governing the operation of Class II wells requires monitoring of active wells and "plugging and abandonment" plans only.[42] California law has established a Hazardous and Idle-Deserted Well Abatement Fund, which collects fees from owners operating a well that currently does not produce oil or gas in order to mitigate potential hazards caused by plugging and abandonment.[43]

Separate from UIC PISC requirements (or lack of them) are the LCFS CCS Protocol requirements. In order to be eligible for LCFS credits, CCS project operators must monitor sites for escaped CO_2 for 100 years after site closure; leak detection checks are required at each well every five years.[44,45,46] These requirements are largely untested, presenting risk and uncertainty for project developers and discouraging investment in CCS. This long-term responsibility can also act as a barrier for tax equity investors and may be prohibitively expensive for smaller firms.

g Most UIC Class II injection wells in California are used for EOR using steam and water, not CO_2.

Inadequate Legal Framework for Obtaining Pore Space Rights

California has not clarified pore space ownership in law. Pore space refers to the fraction of rock volume not occupied by solid matter, which could be used for storing carbon dioxide.[47] CARB's CCS Protocol requires that a project operator must show proof of exclusive right to use the pore space in the storage zone in order to obtain LCFS credits.[48]

In California, there is uncertainty about who owns underground pore space rights.[49] The problem is particularly acute when the property rights to the surface land and to the underground mineral rights have been vested in different parties ("severed"). California Appellate courts have yet to rule on a case concerning whether surface estate owner or the mineral estate owner owns the empty pore space (which, in the case of an oil field, results from the extraction of the mineral resource). Legislatures in North Dakota, Wyoming, and Montana have acted to clarify this issue by vesting ownership of the pore space in the surface owner.[50]

Another problem is that even if private ownership of pore space was clear, fragmented rights to a large underground formation could force operators to engage in complex and potentially expensive negotiations with many property owners. Unitization agreements, in which leaseholders or surface owners agree to consolidate the mineral or leasehold interests over a common source, are commonly used in the oil and gas industry.[51] In most states where unitization rules exist, a certain percentage of landowners must agree to unitize the premises.[52]

Though unitization rules exist primarily to unify development of an entire geologic area or reservoir to reduce inefficiencies in the production process for oil and gas, they also have provisions that reduce the likelihood of legal issues or disputes. For example, if the parties involved in a unitization contract each have unit production shares equivalent to their cost shares, it is in the interest of all the parties to abide by the contract to maximize their profits.[53] Unitization agreements could be helpful for CO_2 storage, by limiting the need for CCS project developers to consult with all landowners to develop CO_2 pipelines and/or wells, and minimize legal issues associated with trespass or plume migration.

Table 4-3 shows approaches different states have taken to clarify pore space ownership and establish unitization agreements.

TABLE 4-3

PORE SPACE & UNITIZATION POLICIES COMPARISON TABLE

	Texas	North Dakota	New Mexico	Wyoming	Montana	California
Pore Space Ownership	Ambiguous[54]	Surface owners[55]	Ambiguous[56]	Surface Owners[57]	Surface Owners[58]	Ambiguous[59]
Unitization Requirements	None[60]	60% approval by ownership[61]	None	80% approval by ownership; lower amounts permitted[62]	70% approval by parties paying costs[63]	None for pore space

In California, there is uncertainty about who owns underground pore space rights. The problem is particularly acute when the property rights to the surface land and to the underground mineral rights have been vested in different parties ("severed").

REVENUE AND COST UNCERTAINTY DISCOURAGE PROJECT FINANCE

From a cost perspective, outside of the well-documented estimations of technology, construction, and operation costs for various components along the CCS value chain, there are a number of project dimensions for which magnitude and uncertainties have a material effect on CCS economic attractiveness. These include: the alignment of industry stakeholders; cost of financial responsibility associated with UIC VI wells; and the initial time required to acquire the necessary permits and establish the feasibility of projects, including social license. These challenges discourage capital investment in CCS projects.

Absent public policy support mechanisms, there is little incentive to capture CO_2 emitted from facilities and inject it into geologic storage. From a revenue perspective, two policy support mechanisms—the LCFS and 45Q—provide cash flows that could justify the capital and operational expenses needed to design, build, and operate the necessary property, plant and equipment for CCS. Uncertainties about the length of time these incentives will be available, however, and their sustained dollar value—especially the LCFS—dampen developer and investor interest in CCS in California.

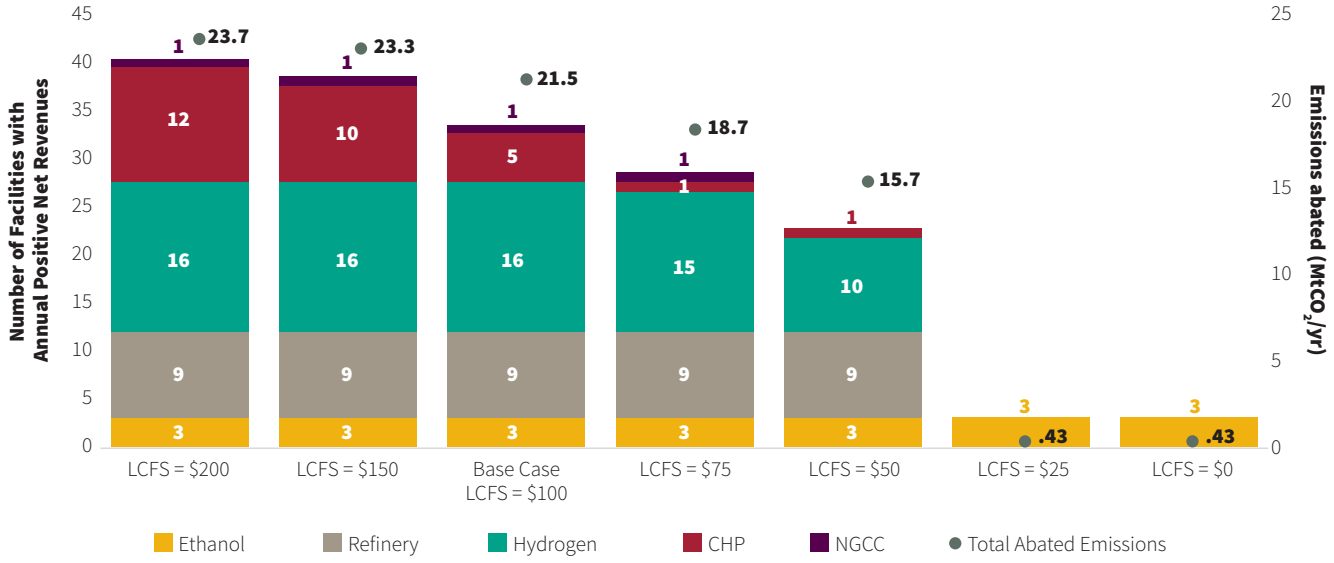
Revenue Challenge: LCFS Credit Market Uncertainty and Policy Risk

The LCFS is a promising financial incentive for eligible CCS projects in California. However, the program includes endogenous risks and uncertainties for would-be CCS investors that have likely hindered the sector's growth despite the high market value of LCFS credits. The volatility of LCFS credit market, its vulnerability to policy changes, and the allocation of a percentage of credits away from the project operators and into a Buffer Account may limit the attractiveness of the LCFS as an incentive for new investments in CCS.

Also, over time, as the state decarbonizes, there will be relatively fewer credits to trade, diminishing the value of the LCFS. Figure 4-3 illustrates the number and kind of facilities that would achieve annual positive net cashflows, assuming a various LCFS credit values.

FIGURE 4-3

IMPACT OF LCFS CREDIT PRICE ON NUMBER OF FACILITIES WITH ANNUAL POSITIVE NET REVENUES



This figure shows the number of facilities that receive annual positive net cash flows as a function of LCFS credit price as well as the total annual emissions of these facilities that could be abated by CCS. *Source: Energy Futures Initiative and Stanford University, 2020.*

Table 4-4 illustrates that the IRR for LCFS-eligible projects (other than ethanol production) would be materially reduced if the LCFS credit price went below $75/tCO_2$. It should be noted that these figures are generally optimistic because they do not account for intra-annual price volatility, which would dampen expected LCFS credit prices.

TABLE 4-4

IRR AS A FUNCTION OF LCFS CREDIT PRICE BY ELIGIBLE CO_2 EMITTING FACILITY TYPE

LCFS Price ($)	Internal Rate of Return (%)			
	Ethanol	CHP	Refinery	Hydrogen
$-	>15%	0-5%	0-5%	0-5%
$25	>15%	0-5%	0-5%	0-5%
$50	>15%	0-5%	0-5%	0-5%
$75	>15%	0-5%	10-15%	10-15%
$100	>15%	0-5%	>15%	>15%
$150	>15%	>15%	>15%	>15%
$200	>15%	>15%	>15%	>15%

This table shows project IRR as a function of LCFS credit price for CCS projects eligible for LCFS credits. Note that for a constant average price below $75/tCO2, IRR is constrained for all source types except ethanol production facilities. *Source: Energy Futures Initiative and Stanford University, 2020.*

Like other emissions credit markets, the LCFS market shows a risk of price volatility over time. Over the past eight years, credit prices have ranged from $25 to over $200 per metric ton.[64,65] This price uncertainty presents a challenge for would-be CCS developers and investors trying to forecast project revenues and profitability that are dependent on credit prices over the life of a CCS project (~20 years).

This variability of LCFS price has a first order effect on the investment case for CCS projects. This is clearly illustrated by CARB analysis done as part of its 2018 Amendments to the LCFS and Alternative Diesel Fuels (ADF) Regulations.[66] Table 4-5 shows the IRR as a function of LCFS price trajectories presented in CARB's report. Given that the LCFS incentive is a state-level policy (as opposed to a federal mechanism), coupled with its relatively short track record, both project developers and outside investors have expressed difficulty in forecasting such volatility. Taken together, the current LCFS credit price—while quite high—is not seen as a bankable source of revenue from which capital can be raised, thus causing investor hesitation in CCS project development.

TABLE 4-5

IRR AS A FUNCTION OF LCFS PRICE TRAJECTORY BY ELIGIBLE CO_2 EMITTING FACILITY TYPE

LCFS Price ($)	Internal Rate of Return (%)			
LCFS Scenario	Ethanol	CHP	Refinery	Hydrogen
Baseline ($100/tCO$_2$)	>15%	0-5%	>15%	>15%
Baseline - Proposed Amendments	>15%	0-5%	0-5%	0-5%
Proposed Amendments	>15%	5-10%	>15%	>15%
Alternative 1	>15%	>15%	>15%	>15%
Alternative 2	>15%	0-5%	>15%	>15%
Baseline - High ZEV	>15%	0-5%	0-5%	0-5%
High Zev Sensitivity	>15%	0-5%	10-15%	0-5%

This table shows project IRR as a function of LCFS credit price, given various LCFS price trajectories, for CCS projects eligible to receive LCFS credits. The first row – Baseline ($100/tCO2) - supposes a flat price trajectory over 15 years. Rows 2-7 correspond to LCFS price trajectories described in CARB's 2018 Amendments to the LCFS and ADF Regulations documentation. *Source: Energy Futures Initiative and Stanford University, 2020.*

Typically, financial instruments like derivatives or options help investors manage price risks across many industries. These types of tools, however, are not available for the LCFS credit market. The lack of hedging instruments coupled with the volatility of the LCFS price add to the uncertainty of the LCFS as an investment incentive.

The LCFS program's carbon intensity (CI) target beyond 2030 is another source of uncertainty. The current LCFS regulation has increasingly stringent annual CI targets through 2030, at which time it will remain at 2030 levels for "subsequent years."[67] As the state continues to decarbonize, it is probable that the CI target will become more stringent; however, the lack of clarity of the future CI targets, beyond the current policy, could introduce more uncertainty into the market in the eyes of would-be CCS investors.

Under the LCFS CCS Protocol, a certain percentage of LCFS credits from all projects must be contributed to an LCFS Buffer Account, which is a reserve of credits that can be used in the event of CO_2 leakage.[68] The amount of credits added to the Buffer Account from any given project depend on a project's risk rating across five dimensions: financial risk; social risk; management risk; site risk; and well integrity risk. Depending on how high or low risk a project ranks in those categories, a predetermined percentage of its credits will be taken and added to the Buffer Account. For the lowest risk projects, eight percent of credits will be added to the Account; a project rated as high risk across all dimensions must contribute about 16.5 percent of its credits to the Account. This reduces the potential revenue flowing back to projects and reduces returns to investors. It also raises questions about how risk is assessed and by whom.

Revenue Challenge: Limitations of the Federal 45Q Tax Credit Design

Although the 45Q credit is a valuable incentive for CCS project development, some aspects of its design limit its effectiveness. The January 2024 deadline for project commencement[h] is challenging, especially given the current economic downturn caused by the international response to COVID-19. The law that included the 45Q incentive passed in 2018, and helpful but incomplete Internal Revenue Service (IRS) guidance was not issued until February and June 2020. Developers, investors, and other stakeholders have only four years to plan, permit, and build an investment case for CCS—a short period given the nascent stage of the industry. It is difficult to meet these deadlines because of the numerous complex preliminary activities that must happen before a developer can begin construction or secure relevant supply contracts.

Although the 45Q credit is a valuable incentive for CCS project development, some aspects of its design limit its effectiveness. The January 2024 deadline for project commencement is challenging, especially given the current economic downturn caused by the international response to COVID-19.

The 45Q tax credit may not cover the full costs of CCS projects alone, but it is a significant source of revenues and can be a foundational component of covering a project's costs. The duration of 45Q benefits (12 years) is however, shorter than the lifespan of a typical capture facility (typically 20 or more years), another deep uncertainty among developers hoping to earn revenues for the entire life of the investment. By comparison, the wind power production tax credit (with a similar format and objective as 45Q) was established in 1992 and remains available through 2020,[69] although its expiration/reauthorization have sometimes hindered development.[70]

Also, few institutions are equipped and motivated to participate in the tax equity markets that rely on companies having large tax burdens against which the credits become valuable; the economic recession brought about by policy response to COVID-19 has reduced company profits and with it their tax burdens, meaning fewer companies are in a position to lend money to CCS developers.

Finally, there is recapture risk – the possibility that the tax equity investor would have to refund tax credits previously claimed in the event of CO_2 leaks; this is of

h Note: There is guarded optimism that Congress will extend this date, but that is currently unknown.

particular concern to investors. Guidance proposed in June 2020 by the IRS includes a stipulation that, in the event of CO_2 leakage, a project developer's tax credits can be "recaptured" for CO_2 injected during the previous five years.[71] The amount of credits is calculated based on the volume of CO_2 leaked and is attributed on a last-in-first-out process over the five-year period. The entity that received the tax credit remains liable for that recapture risk until the end of the period, even if the facility is sold or transferred to another party or if there was a contract with a third-party assuring the permanence of the CO_2.[72] The inability to sever that liability reduces tax investor interest in CCS projects under 45Q, especially relative to the less risky renewable energy tax equity investment opportunities in wind power.

Cost Challenge: Aligning Players, Permitting, and Financing

Building a CCS industry from its nascent state will require overcoming several distinct challenges related to scaling and laying of groundwork, sufficient to establish investor confidence. The first issue is the classic first mover or "chicken-and-egg" problem, and the second is a matching or coordination problem between different potential players in the industry.

Without financing, CCS projects will not be built. To secure financing however, most financers require the completion of a certain amount of front-end—and expensive—work to demonstrate viability (FEED studies, securing partners and suppliers, permitting, etc.). This creates a dilemma for project developers: they need financing to start work, but to secure financing, they must have already started the work.

Typically, the solution is for one party—typically the developer—to take the risk and begin financing the project off their balance sheet to get the project started before securing additional outside financing. However, most of the companies (such as the oil and gas majors) interested in building CCS have a global portfolio of revenue-generating opportunities. Indeed, while some projects may be considered risky there is a greater set of experiences and capabilities that can be brought to bear on such projects, compared to a much newer enterprise such as CCS.

A similar problem exists along the CCS value chain: building one part of a CCS project has little value absent complementary infrastructure, and until the right conditions are met, the counterparty risk may be too high for firms to make the necessary long-term financial commitments. CO_2-emitting facilities are reluctant to sign contracts before storage or offtake projects are in late-stage development; meanwhile, storage and pipeline projects are difficult to finance absent contracts for their use. Moreover, as a hedge against bankruptcy or other counterparty risks, both sides want to have multiple providers (or off takers), or at least multiple prospects, before building.

Other industries have overcome similar "chicken-and-egg" problems by vertically integrating or investing in a larger share of the value chain rather than a single component. But in the CCS industry, the capital needs of a large portion of the value chain are greater than most investors and developers are willing to provide. There may also be simple matching or coordination problems: if different parties are, in fact, committed to the project but are unaware of the level of commitment or existence of other parties along the value chain, parties may be less willing to commit to the project.

Cost Challenge: Financial Responsibility Associated with UIC Class VI Wells

Under EPA's federal UIC VI well permit, a trust fund is established by a project developer to cover the costs of: corrective action, emergency and remedial response, injection well plugging, PISC, and site closure. An illustrative example is the FutureGen project in Illinois that was a Class VI demonstration project that established an approximately $52 million trust fund for injecting 1.1 $MtCO_2$ annually.[73] This project-specific, upfront cost burden has a non-trivial effect on overall project returns. Using FutureGen as a baseline, a proportioned trust fund established for an ethanol plant would reduce IRR by 10 percent (e.g. if IRR was 20 percent, it would become ~18 percent). While coverage is clearly important, a more efficient approach may be to pool funding into a central storage facility that serves multiple capture facilities.

A problem exists along the CCS value chain: building one part of a CCS project has little value absent complementary infrastructure, and until the right conditions are met, the counterparty risk may be too high for firms to make the necessary long-term financial commitments. CO_2-emitting facilities are reluctant to sign contracts before storage or offtake projects are in late-stage development; meanwhile, storage and pipeline projects are difficult to finance absent contracts for their use.

LACK OF PUBLIC AWARENESS AND SUPPORT FOR CCS

Resources for the Future, a prominent think tank, noted the following about public acceptance issues with CCS: "Several considerations play a role in public opinion about CCS: acceptance of fossil fuels (as CCS may be viewed as prolonging the role of fossil fuels in the economy); acceptance of pipeline construction; perceived safety of transportation and storage of CO_2; perceived effectiveness of CCS; the extent to which other climate solutions are implemented in addition to CCS; and several other considerations that can shape an individual's view of CCS and, therefore, overarching public opinion."[74,75]

Public acceptance of CCS is a cross-cutting issue, potentially affecting each category of challenges described in this chapter: the ambiguous position of the state; complex and untested regulatory processes; and revenue and cost uncertainties. Public attitudes can make or break a CCS project and are wide ranging and highly variable. This is due in part to the fact that these are relatively new infrastructures and technologies with which the public is unfamiliar.

Analysis suggests that individuals are influenced by relationships with their communities; better community relationships translate into greater individual support for CCS.[76] It is important for California as it considers the role CCS will play in its zero-carbon future, to prioritize outreach and education to all Californians, but especially those in affected communities. It is critical that these communities and stakeholders have input into policy development, CCS project planning, permitting, and all other stages of the process to ensure CCS will promote a just transition to a zero-carbon California.

Concern that CCS Allows for Continued Fossil Fuel Use

The trajectory of technologies designed to reduce GHG emissions from fossil fuels is uncertain.[77] A legitimate barrier to CCS stems from concerns that CCS, regardless of emission reduction value, provides a pathway for continued fossil fuel use, including concerns about the other negative attributes of fossil fuels such as pollutants and negative community impacts.[78]

It is important for California as it considers the role CCS will play in its zero-carbon future, to prioritize outreach and education to all Californians, but especially those in affected communities. It is critical that these communities and stakeholders have input into policy development, CCS project planning, permitting, and all other stages of the process to ensure CCS will promote a just transition to a zero-carbon California.

Low Public Awareness and Varied Opinions of CCS

Public awareness of CCS in the U.S. as a cost-effective climate solution is generally low. Among those with some knowledge of CCS, perceptions are highly varied and tend to be based on project-specific or local knowledge. While new energy technologies often face skepticism and even opposition from the public, a review of the literature on public opinion of CCS found that CCS is "reluctantly accepted" by the public and rarely receives either strong opposition or strong approval.[79]

Increasing knowledge about CCS could change public opinion; the most important predictor for acceptance of CCS, however, is the perception of its benefits, followed by perception of risks and trust in stakeholders.[80] Specifically, the perception of local benefits is a significant predictor for acceptance. Box 4-1 describes the Hydrogen Energy California (HECA) CCS project that failed, partially due to public opposition.

BOX 4-1

HYDROGEN ENERGY CALIFORNIA CCS PROJECT AND PUBLIC ACCEPTANCE

Background

Hydrogen Energy California (HECA) was an early experimental CCS project that began as a joint venture between BP and Rio Tinto via cooperative agreement with U.S. DOE. HECA received funding from the Clean Coal Power Initiative and the American Recovery and Reinvestment Act in 2009.[81] The facility, based in Kern County, proposed to use coal and refinery waste to generate hydrogen for electricity, capturing and storing 90 percent of CO_2 emissions. The captured CO_2 was to be used for EOR.[82] The proximity to oil and gas infrastructure made Kern County an ideal site for HECA CCS: the area accounts for nearly 75 percent of California's active oil and gas wells and over 70 percent of the state's total oil production.[83] However, the density of oil and gas facilities in populated areas, the poor air quality, and the high rates of poverty also made Kern County an important locus for environmental and racial justice organizations in California.

From inception, HECA CCS drew criticism from environmental activists and farmers across the state, and local organizers mobilized county-level opposition to the project. Particularly active were Sierra Club of California, Greenaction for Health and Environmental Justice, Central California Environmental Justice Network (CCEJN), Association of Irritated Residents (AIR), and a community group called HECA Neighbors. In 2011, Massachusetts-based SCS Energy LLC acquired the project, leading to significant changes to the scope of operations for HECA CCS and raising additional community concerns. While HECA was originally conceived to be a hydrogen production facility only, SCS Energy determined the plant would also need to manufacture fertilizer to maintain financial viability.[84] Concerns among the activists and area residents included:

- Trucks and trains transporting coal, petroleum coke, fertilizer, and waste products would reduce air quality and damage farmland, via diesel emissions or by spreading coal dust.
- The gasification process would release high concentrations of NOx, particulate matter, heavy metals, and other pollutants.
- Fertilizer produced by the facility as a byproduct of gasification posed a risk of explosion.
- Water required for the project would be diverted from an over-tapped aquifer, risking drought in an agricultural economy and pollute other, higher-quality aquifers.[85]

Between escalating public relations and legal fights with environmental justice organizers and a loss of momentum with critical stakeholders, progress on the HECA CCS project stagnated. In 2013, California-based Occidental Petroleum, which had planned to buy CO_2 captured at HECA for injection at its Elk Hills oil field in Kern County, moved to Texas – putting a critical source of project revenue at risk.[86] Ultimately, Occidental's California spinoff, California Resources Corporation, decided not to pursue the project and HECA CCS lost its federal funding shortly thereafter.[87, 88] In 2014, HECA CCS proposed injecting CO_2 directly under the facility, but local agricultural zoning laws prohibited the plan from moving forward. SCS Energy ultimately withdrew its application to continue the HECA CCS project on March 3, 2016.[89]

Lessons Learned

HECA highlights some key lessons on public engagement and stakeholder outreach for future CCS projects. Focusing only on the global climate benefit is not adequate to get local communities on board – local benefits must exist and be articulated, and stakeholders must be engaged in honest and transparent conversations. Criticism from activists, organizers, and mobilized residents of Kern County centered on issues of local air and water quality, land use, and the impact of toxic waste such as coal dust. Farmers were particularly concerned with the effects of CO_2 injection near or beneath their property, and the risks to the local aquifers in a drought-prone region. Greenaction raised concerns about minimal efforts by SCS Energy to engage Hispanic and Spanish-speaking Kern County residents. CCEJN organizers protested that HECA failed to adequately address local health outcomes by connecting area residents to health services. Some area residents were pleased with the forecast that the project would create some 2,000 temporary construction jobs and 200 permanent positions; however, environmental justice activists argued that staff positions at HECA CCS would most likely be filled by employees from outside the county.[90] Guarantees to hire locally for some percentage of positions and engagement with area schools, perhaps in exchange for local tax abatements, would bolster a compelling argument for CCS projects.

Overall, the HECA CCS project faced a credibility gap, particularly once goals began to shift following the 2011 acquisition by SCS Energy. Future CCS deployments must be clear, consistent, and strategic in their messaging and conduct honest and transparent public engagement with community, regional, and state-wide groups to ensure local needs are met and environmental injustice is not perpetuated.

Public trust of CCS is also influenced by trust in the "stakeholders" involved in local projects, including CCS developers, energy companies, government agencies, and NGOs. Analysis suggests that trust increased if decision-makers sought input from diverse stakeholder groups and communicated honestly. Support for CCS was also influenced by media coverage and information about how CCS is used in other countries. [91]

Public perceptions that contribute to negative opinions of CCS include hesitancy about the technology's risks, its lack of a long-term track record, and its costs and the investment tradeoff compared to other abatement options.[92] As noted, public criticism of CCS often centers around the fact that it is an "end-of-pipe" solution that does not decrease the use of fossil fuels. Worries about the risks of CCS, namely the risk of leakage, are also commonplace.[93] Other concerns about CCS include its perception as a "delaying tactic" that forestalls necessary climate change mitigation actions.[94]

Public approval or disapproval of CCS also hinges on how the technology's value is framed and how that framing aligns with an individual or group's preexisting attitudes or values. For example, communicating the economic benefits of CCS will be more convincing to climate change skeptics than information about how CCS can mitigate climate change.[95]

Historic Inequities in Energy Infrastructure Siting

Energy infrastructure is disproportionately located in or near low-income, high-minority neighborhoods, polluting the air and water, contributing to negative health outcomes, and lowering property values in "fence line communities," or the communities living adjacent to polluting energy infrastructure.[96,97] In the U.S., residents of fence line communities are disproportionately African Americans who have higher rates of asthma, respiratory illness, and cancers than the general population.[98]

Numerous California agencies have made commitments to help ensure that communities impacted by the location of energy infrastructure are included in decision-making processes through open and transparent discussions.[99,100,101] For carbon capture, infrastructure siting is straightforward as the candidate facilities already exist; decisions are limited to identifying the best candidate facilities ultimately for retrofitting with CO_2 capture technologies. Of the potential retrofit candidates identified in Chapter 3, 63 percent are in urban areas. While carbon capture is an emissions-reduction technology that can provide local benefits (i.e. improved air quality), it is important that impacted communities receive other benefits, such as jobs, and are included in decision-making processes related to CCS.

While carbon capture is an emissions-reduction technology that can provide local benefits (i.e. improved air quality), it is important that impacted communities receive other benefits, such as jobs, and are included in decision-making processes related to CCS.

For pipeline routing and CO_2 storage, there is a degree of optionality as saline formations are expansive and the exact location of the storage site can be in a range of potential surface locations. CO_2 storage sites and pipeline routing decisions in California will largely affect rural communities as the potential CO_2 storage sites identified in Chapter 3 are nearly all in rural locations.

CHALLENGES WILL LIMIT CCS DEVELOPMENT, SOLUTIONS ARE NEEDED

The four types of challenges described in this section—ambiguous position of the state on the future role of CCS; complex and untested regulatory process for getting permits for CCS; revenue and cost uncertainty discourage project finance; and lack of public awareness and support for CCS—and the specific issues within those categories limit CCS development today. The current policy and regulatory landscape for CCS in California could by 2030, at best, yield a small number of site- and industry-specific projects. This outcome would likely not involve large emitters, and would not achieve the significant emissions reductions needed from the industrial and power sector emissions to meet the state's 2030 and 2045 climate mitigation goals.

At the same time, the LCFS is providing significant financial incentives for CCS projects in other states (so long as they provide transportation fuel in California; see Box 2-1). For this reason, project developers are investing capital (and are therefore stimulating local economic development, creating jobs, and providing other local benefits) in other states. By addressing even some of these California-specific challenges, policymakers can create an enabling environment for CCS project development in the state. A variety of solutions aimed at addressing the California-specific challenges exist and are detailed in full in Chapter 5. California has the opportunity to lead the world in CCS development. To do so, however, it needs to rapidly condition its market to support and accelerate this critical option for meeting the state's ambitious climate goals.

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Chapter 5

A Policy Action Plan for Maximizing the Value of CCS in California

California has a strong foundation for CCS. State policy actions can maximize the value of CCS for achieving California's economywide decarbonization goals. This chapter offers an Action Plan for California policymakers who seek to promote technology optionality while pursing carbon neutrality; motivate the private sector to decarbonize; enable economic and reliability benefits from existing industries and power generation; and establish a foundation for new clean energy industries and jobs.

California's clean energy transition relies on the formation of broad coalitions working together to achieve common and critical decarbonization goals. These coalitions must include policymakers, environmental and social justice advocates, industry leaders, scientists, local communities, and other key stakeholders. This study is designed to provide guidance for such efforts by identifying near-term actions, key enablers, and opportunities for action on CCS.

CCS is a critical decarbonization pathway for helping California to meet its 2045 carbon neutrality goal. CCS also supports related goals that are fundamental enablers of the clean energy transition and key to building the necessary coalitions:

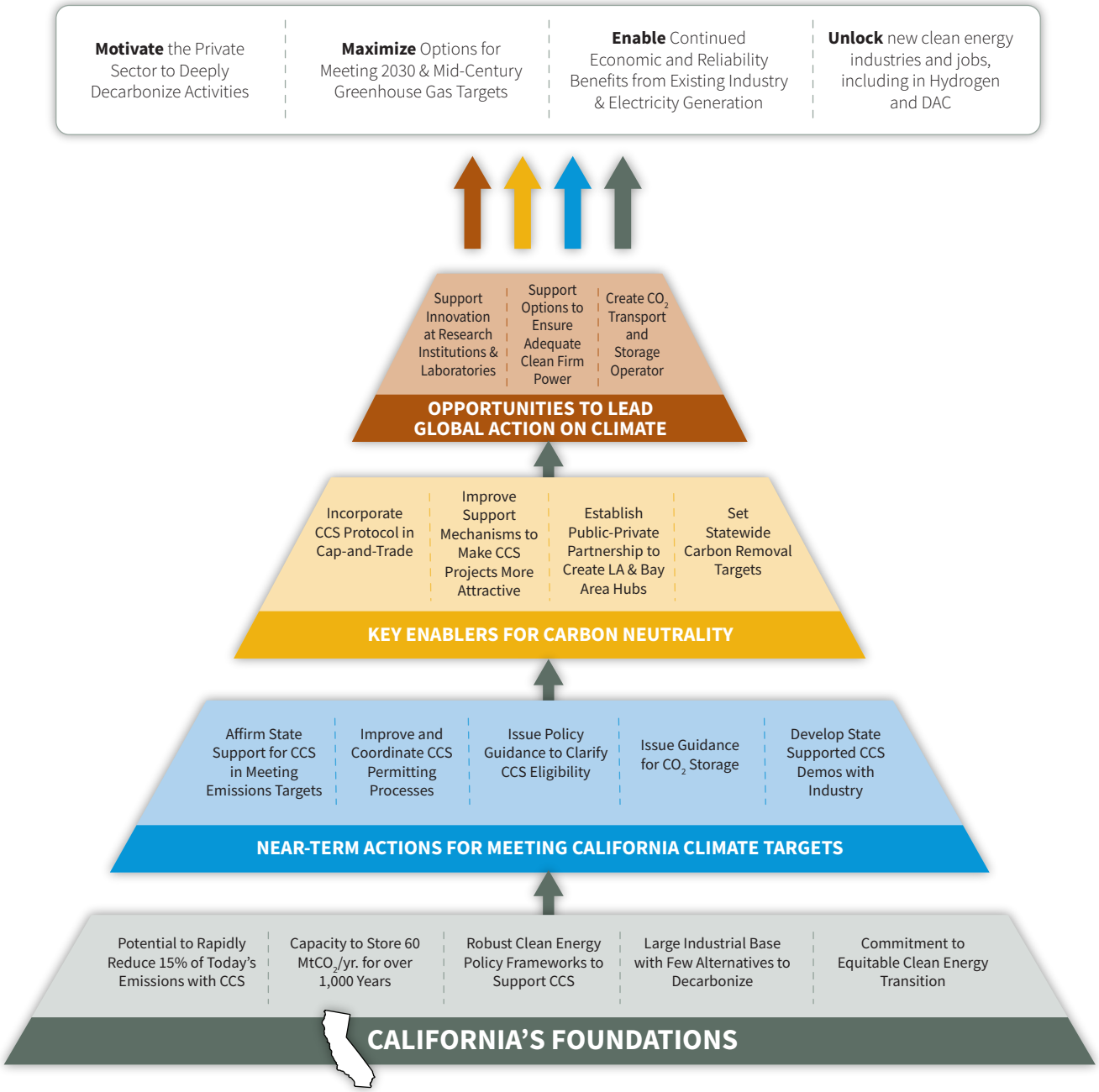
- Maximizing options for meeting 2030 and 2045 GHG targets to reduce associated costs, improve the likelihood of achieving the targets, and foster innovation;
- Motivating the private sector to deeply decarbonize its activities and products;
- Enabling continued economic and reliability benefits from existing industries and power generation. Industries, such as oil refining, cement, and electricity, can employ CCS to rapidly reduce emissions while preserving existing jobs, economic productivity, and infrastructure; and
- Unlocking new, potentially multi-billion-dollar clean energy industries—such as hydrogen, CO_2 utilization, DAC, and fuels from biomass waste—creating new jobs in the process.

This study identified sufficient geologic storage capacity in California to safely and permanently store 60 $MtCO_2$/yr—the equivalent of total electricity sector emissions in 2017—for 1,000 years. In addition, California's industrial economic base is largely concentrated in a few regions of the state, providing a unique opportunity to deploy shared CCS infrastructure to rapidly reduce close to 15 percent of the state's emissions. This is especially important for key economic subsectors such as refining and cement where there are few, if any, other technologies for deep decarbonization. Also, the state's ambitious GHG reductions policies, combined with the CCS Protocol for LCFS, offer important opportunities for CCS. Finally, the state's policy commitment to an equitable and just clean energy transition establishes the basis for a focus on CCS, which creates opportunities for new industries and jobs, and can lower conventional pollutants, which disproportionately affect disadvantaged and minority communities.

Despite the strong federal and state incentives, there are currently no operational CCS projects in California. There are, however, several CCS projects in active development. A small number of developers with plans to take advantage of the 45Q tax credit and the state's LCFS will be invaluable first movers. These project developers also plan to generate additional revenues by selling electricity or fuels and are taking advantage of existing infrastructure and their proximity to quality CO_2 storage resources.

FIGURE 5-1

A POLICY ACTION PLAN FOR CCS IN CALIFORNIA TO MEET THE HIGH-LEVEL GOALS



The analysis in this report informed the establishment of high-level goals for CCS in California at the top of the figure. California has a strong foundation for CCS development. Key drivers – near-term actions for meeting climate targets, enablers of carbon neutrality, and opportunities to lead global action – inform and increase CCS project development in specific areas of recommended actions.
Source: Energy Futures Initiative and Stanford University, 2020.

Deployment of innovative clean energy technologies takes time, dedicated policy support, and the application of lessons learned from experience—while protecting the environment and local communities.

California is at a crossroads for CCS development. If CCS is to play a meaningful role in meeting the state's 2030 emission reduction targets and midcentury carbon neutrality ambitions, California needs to address the regulatory and policy barriers to CCS deployment to enable the state's largest emitters to rapidly develop CCS projects. The state also needs to clarify its support for those projects already in the early stages of development.

This analysis identified a suite of policies to support CCS deployment at scale in California that are fully aligned with the state's high-level climate goals. These recommendations build on the strong policy, innovation, and geologic foundations—as described in this report—that will help to both maximize its emissions reduction value while preserving the grid reliability and economic benefits of key sectors in the state. Building on these strong foundations, this analysis has identified three key drivers for maximizing the emission reduction potential of CCS: the need for near-term actions; key enablers for carbon neutrality; and opportunities to lead global action on climate. These foundations, drivers, policy recommendations, and high-level goals are illustrated in Figure 5-1 and discussed in detail in this chapter.

NEAR-TERM ACTIONS FOR MEETING CALIFORNIA'S CLIMATE TARGETS

California's state agencies should take immediate actions to maximize technology options for meeting its near-term 40 percent economywide emission reduction target by 2030, and to pave the way for meeting longer-term targets.

Affirm State Support for CCS in Meeting Emissions Targets

CCS projects can have immediate and long lasting environmental, economic, and jobs benefits to nearby communities. State and project development activities should prioritize projects that maximize these benefits.

As noted in Chapter 3, carbon capture can potentially provide local air quality benefits for communities living near refineries and cement facilities, which emit high levels of criteria air pollutants. Because each CCS project is unique in design and circumstance, however, the local community benefits and impacts will vary by project and location.

CCS projects can also stimulate local economic activity, including new construction, operations, and maintenance jobs. The Boundary Dam CCS facility in Canada, for example, employed 1,700 people at peak construction, while the Alberta Carbon Trunk Line project employed 2,000.[1] While the long-term operation of a carbon capture facility only requires around 20 full time employees, studies show that the deployment of CCS can generate large local economic multipliers.[2]

The analysis in Chapter 3 also found that approximately 63 percent (48 out of 76) of candidate capture facilities are located in urban areas, while the majority of pipelines and all CO_2 storage sites would be sited in rural locations. The economic benefits associated with job training, as well as temporary and permanent positions, could help these communities transition to low carbon economies with limited impacts on jobs and development.

California's manufacturing sector, which includes the chemical and refining industries, accounted for roughly $315 billion in economic output (11 percent of gross state product) in 2018, with more than 35,000 firms employing 1.3 million employees (eight percent of all non-farm employment).[3] The traditional energy sector, including oil and gas, accounted for nearly 412,000 jobs in California in 2019.[4] The use of CCS could enable difficult-to-decarbonize industries to continue making large contributions to California's economy while dramatically reducing their GHG emissions and providing jobs for transitioning conventional energy to clean energy skillsets.

Issue Policy Guidance to Align State Agencies

California has recently signaled that CCS projects are a viable carbon abatement strategy. The CARB 2017 Scoping Plan noted that CCS "offers a potential new, long-term path for reducing GHGs for large stationary sources."[5] In 2018, CARB adopted the CCS Protocol under the LCFS.[6] In 2019, the state affirmed CCS as a feasible pathway for

decarbonizing the cement industry in the CEC's report on 2050 low-carbon scenarios.[7]

Strong policy guidance, such as an executive order, could affirm the conclusions of CARB and the CEC about the need for and value of CCS. An executive order directing state agencies to align their relevant CCS regulatory activities with key high-level goals, could make a large contribution to the state's decarbonization goals.

California's manufacturing accounted for roughly $315 billion in economic output in 2018—11 percent of gross state product—with more than 35,000 firms employing 1.3 million employees... The use of CCS could enable difficult-to-decarbonize industries to stay in business and continue making a large contribution to California's economy while dramatically reducing their GHG emissions.

Promote Local Community Support through Stakeholder Engagement and Explicit Benefits

Project developers, local governments, and community representatives should work collaboratively to maximize and share the benefits of CCS projects. Such engagements could include establishing community benefit agreements (CBAs)[a] between project developers and a coalition of community representatives to ensure that key benefits accrue to impacted communities near the project.[8] A useful example is the CBA negotiated as part of the expansion of the Los Angeles International Airport: it included multiple regulatory jurisdictions and evaluated the environmental, social, and health impacts of the construction projects and facility operations on the local community.[9]

Preserve and Grow Existing Industry Workforce to Support Clean Industrialization

A transition to carbon neutrality by midcentury will likely require structural shifts in California's economy. While innovative industries may adapt and cater to new conditions, energy intensive and difficult-to-decarbonize sectors, like manufacturing, could have difficulty achieving climate targets while maintaining economic output.

As noted, CCS activities could support employment for skillsets which may be impacted by the clean energy transition. Through CCS, many industrial and traditional energy talents could be re-deployed, leveraging current expertise to contribute across the emerging CCS value chain. For example, geologists and petroleum engineers focused on oil field exploration and development could focus their efforts on characterizing safe, secure geologic storage resources. Any additional training needs for CCS jobs should be supported by state and union training programs.

CCS also enables new clean energy pathways that create jobs and potentially multi-billion-dollar industries in California, such as clean hydrogen, CDR, and carbon utilization industries. These jobs and industries are discussed in detail in the section on "Opportunities to Lead Global Action on Climate."

Strong policy guidance, such as an executive order, could affirm the conclusions of CARB and the CEC about the need for and the value of CCS. An executive order directing state agencies to align their relevant CCS regulatory activities with key high-level goals could make a large contribution to the state's decarbonization goals.

Improve and Coordinate CCS Permitting Processes

Building new infrastructure to support the emerging CCS industry requires strong financial, policy, and regulatory support. The regulatory environment for CCS in California is relatively untested, which makes it difficult to acquire the necessary permits and access the financing necessary to move projects forward. Distinct CCS project components—the capture facility, transportation infrastructure, and

a CBAs are legally enforceable agreements that commit a coalition of community representatives to supporting a development in exchange for specific amenities and mitigation from project developers for the host community. CBAs differ in several important respects from Public-Private Partnerships: they are typically negotiated and executed by community members and representatives instead of municipal entities; however, in California, municipal authorities are able to participate in and sign CBA agreements on behalf of the community.

storage site—may cross multiple counties, cities, and potentially state boundaries and require different technical expertise. As discussed in Chapters 2 and 4, more than 15 local, state, and federal agencies can be involved in permitting a CCS project in California. The state should improve the coordination of CCS project permitting while preserving community inputs and unique state and local prerogatives. This could help shorten project development timelines and accelerate the associated emissions reduction benefits.

Appoint a Lead Coordinating Agency for CCS Activities

California's executive branch could improve coordination of CCS project development by assigning a lead coordinating agency for CCS permitting activities. The coordinating agency could work with the various permitting agencies to develop clear permit review timelines, establish permit submission sequencing guidelines, and support transparent review processes. The coordinating agency could also be the primary point of contact for permit applicants. This coordinated permitting process would strengthen critical aspects of the regulatory process, including public comment periods, by improving transparency and clarifying opportunities for public engagement.

A CCS coordinating agency would be especially useful for assisting with the CEQA process (described in detail in Chapter 2 and Appendix A), which requires a singular "lead agency" to oversee the CEQA review. The CCS coordinating agency could advise the CEQA lead agency or directly serve in that role. The CCS coordinating agency could leverage its technical expertise and experience, ensuring that CCS projects are developed in a timely fashion and facilitate parallel review processes, when possible.

Finally, the CCS coordinating agency's responsibilities could also include liaising with relevant federal agencies on CCS permitting, including EPA for permanent deep saline reservoir geologic storage wells, the Pipeline and Hazardous Waste Materials Safety Administration (PHMSA) for interstate pipelines, and with the relevant federal agency when a joint a CEQA and NEPA process is required (described in detail in Appendix A).

California has experience creating a lead coordinating entity to improve the permitting process for energy infrastructure. Power plant siting in California dramatically improved after the state centralized permitting authority for new power generators at the CEC.[10] The CEC developed a 12-month licensing process for power plants and their associated infrastructure (e.g. transmission lines) that also ensured environmental protections.[11] This could serve as a model for CCS project coordination.

Establish a Multiagency Work Group

California could establish a multiagency work group to identify overlapping or redundant processes and increase coordination to streamline permit applications and reviews. Such a working group could, for example, include CARB, CalGEM, the State Water Resources Control Board (SWRCB), and the California Geological Survey (CGS), in consultation with the U.S. EPA Region 9, to coordinate a joint review of how the geologic information for each storage project will be reviewed, explore options to appoint a science lead and coordinator, and harmonize application requirements for Class VI well permits and LCFS Permanence Certification.

The Desert Renewable Energy Conservation Plan (DRECP) is a current multiagency effort designed to enable renewable energy projects to be developed in a timely, transparent, and thorough way with the support of state, federal, local, and tribal governments. Box 5-1 details this and one other recent example of multi-agency collaboration efforts that have enabled cross-jurisdictional renewable energy projects to be sited, planned, and permitted in a coordinated and environmentally safe manner.

A coordinated permitting process would strengthen critical aspects of the regulatory process, including public comment periods, by improving transparency and clarifying opportunities for public engagement.

BOX 5-1

CALIFORNIA INFRASTRUCTURE PERMITTING MODELS FOR CCS

The **Desert Renewable Energy Conservation Plan (DRECP)** is a multi-agency partnership with the goal of streamlining permitting of renewable energy projects in the Mojave and Colorado/Sonoran Desert area while preserving desert ecosystems and cultural and tribal heritage sites, as well as protecting outdoor recreation areas in this popular area. The DRECP is led by the Renewable Energy Action Team, comprised of the Bureau of Land Management (BLM), U.S. Fish and Wildlife Service, California Energy Commission (CEC), and the California Department of Fish and Wildlife (CDFW), and involves local governments, other state agencies, tribal governments, and the public.[12]

In total, the DRECP covers 22.6 million acres of private and public land through seven California counties, 10.8 million which are under the jurisdiction of the BLM. Since 2009, the DRECP has enabled dozens of renewable energy projects to be permitted in a coordinated manner that takes into account landscape-level issues that individual permitting on an agency-by-agency and project-by-project basis can fail to consider. In total, the state estimates that approximate 17-19.5 GW of renewable energy capacity will be able to be built in the DRECP plan area by 2040 to help California achieve its renewable energy goals.[13] Thus far, 544MW of solar energy have been authorized to operate under the DRECP. Three projects, totaling 1100MW of electricity, are currently under review by the BLM.

Applicability for CCS: the DRECP identified 388,000 acres of "Development Focus Areas" based on energy generation potential and low environmental impacts and provides a streamlined easily-understood permitting path with requirements for project developers on these focus areas.[14] A similar effort could be undertaken for CCS to identify priority areas for CCS infrastructure development that would maximize emission reductions and minimize environmental impact.

The **California Marine Renewable Energy Working Group** is an interagency collaboration that seeks to reduce uncertainties in the regulatory processes of marine renewable energy, provide information on potential impacts and user conflicts, and facilitate the development of agreements to improve coordination of state and federal permitting processes.[15] The group is chaired by the California Ocean Protection Council that includes the CEC, CDFW, State Lands Commission, Coastal Commission, and CPUC.

In 2010, the California Natural Resources Agency, CalEPA, and CPUC signed a Memorandum of Understanding with the Federal Energy Regulatory Commission (FERC) that established a procedure for coordinated and efficient reviews of proposed hydrokinetic projects that considers environmental, economic, and cultural impacts. In 2011, the Working Group issued Permitting Guidance that detailed the licensing and permitting process for early test and pilot hydrokinetic and offshore wind projects. This document provides project developers with clear guidelines for permits and processes that must be obtained for a test or pilot project; it details a suggested sequence for permitting and leasing; and it provides a detailed overview of all potentially relevant state and federal agencies and cases in which each agency would be involved.[16]

Applicability for CCS: Overall, the Marine Renewable Energy Working Group serves as a venue for coordination among state agencies to address regulatory issues and a centralized first point of contact for energy project developers. Early consultation with the state agencies can help developers identify the most efficient pathway for regulatory authorizations, and involved agencies could inform developers about specific stakeholders, natural resources, and/or marine activities that may require project modifications or specific consultations.[17] A similar group could be established for CCS permitting that includes the relevant permitting agencies. This could be particularly beneficial for permitting dedicated geologic storage (Class VI wells), which must be done by the U.S. EPA Region 9. A CCS permitting working group could include a core group of members from the U.S. EPA Region 9, CEC, CPUC, CARB, and CalGEM, as well as representatives from local air districts, local water districts, cities, counties, and tribal governments in areas with potential for CCS infrastructure.

Consider Seeking Class VI Primacy

CalGEM could consider seeking primacy for Class VI wells, based on its state-level expertise in California's geologic resource development.[18] While this study recommends specific improvements to certain regulations, the entire project permitting process would benefit from clearer regulatory roles, responsibilities, and requirements for CCS projects pursuing dedicated geologic storage via Class VI wells. As described in Chapter 4, one of the longest permitting processes for a CCS project involves a Class VI well. In the only two states that have obtained primacy from the EPA, North Dakota and Wyoming, Class VI primacy offers regulatory certainty to developers of CCS, ensuring rules are tailored to the unique geologic and policy circumstances of each state.[19] Wyoming and North Dakota both received primacy from EPA Region 8; the process took approximately five years for North Dakota [20] and nearly three years for Wyoming.[21,22] EPA Region 9 has not yet granted Class VI primacy to any other states in the region,[b,23] creating uncertainty about the length of this process.

The EPA offers detailed guidance on the process, should California decide to apply for primacy. There are four established phases of applying for and receiving primacy: pre-application, completeness review, application evaluation, and rulemaking. Through each of these phases, EPA guidance emphasizes continued dialogue between the state and EPA to address questions and issues that arise.

For an application to be reviewed, six "core elements" are required – a Governor's letter, an Attorney General's letter, a program description, a memorandum of agreement, a copy of the state's UIC statutes and regulations, and public participation documents. A primacy application is deemed complete when a final ruling is signed by the EPA Administrator and codified in the Federal Register.[24]

Issue Policy Guidance to Clarify CCS Eligibility

As new clean energy technologies emerge, there are often questions regarding their compatibility with existing policies and regulations. This is especially relevant for CCS, where system components often span multiple jurisdictions and sectors. Short of major legislative actions, there are near-term opportunities where California should clarify the role of CCS in existing policies and regulations.

Issue Guidance on CCS Eligibility Under SB100, IRP, and IEPR

As described in Chapter 4, California's IRP process was established by SB350 in 2015, which set a 50 percent renewable energy target for the state's power sector; a target of, doubling energy efficiency in commercial and residential buildings; and promotion of transportation electrification by 2030.[25] SB100, which became law in 2018, strengthened the state's RPS and added a power sector emission reduction target, calling for 60 percent renewables by 2030 and zero carbon electricity by 2045.[26]

Planning for these goals occurs through the IRP process.[27] The CPUC oversees this effort with the goal of ensuring that California has safe, reliable, and cost-effective electricity supply, enabling California to meet its electricity emission reductions targets.[28] Presently, CCS is not included in this process. Separate but related, the CEC's IEPR process informs ways of conserving resources, ensures reliable, secure, and diverse energy supplies, and protects the environment and public health by assessing trends and issues in the electricity, gas, and transportation fuel sectors.[29] The state could fully consider the potential economic and emissions reduction benefits afforded by NGCCs with CCS in the IRP as well as IEPR planning processes.

SB100's language is clear that "100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies" must come from "eligible renewable energy resources and zero-carbon resources" by December 31, 2045. The state could include CCS as an eligible resource under SB100 where electricity generation projects produce electricity with zero carbon emissions. Facilities may use CCS and cover their remaining emissions with negative-emissions technologies, offsets, or by consuming a renewable fuel to reach zero carbon. For example, combining DAC with CCS at an emitting facility could lead to net zero emissions. Deploying a DAC capability on-site could be sized to

b EPA Region 9 consists of Arizona, California, Hawaii, Nevada, Pacific Islands, and 148 Tribes within Arizona, California, and Nevada.

capture the equivalent of any remaining emissions not captured by CCS. The CO_2 captured by the DAC facility then could be combined into a single CO_2 stream for transport and sequestration.

A generation facility with CCS may be eligible to the extent that its emissions are captured. The analysis detailed in Chapter 3 shows that a power grid supported by a diverse portfolio of zero-carbon firm resources including CCS can achieve zero-carbon emissions at a much lower cost than one that excludes them. This aligns with public comments from a group of energy experts to the CEC's "*SB100 Joint Agency Report: Charting a Path to a 100% Clean Energy Future.*"[30] It is also supported by major studies of reaching economywide carbon neutrality that explicitly value carbon removal options that include CCS.[31]

Issue Guidance for CO_2 Storage

In California, the lack of legal clarity on geologic pore space ownership creates a thicket of legal issues for developers of projects that include CO_2 storage. Also, uncertainty and management of long-term liability of stored CO_2 for years or decades is an often-cited barrier to CCS project development in the state. California state agencies should provide additional regulatory guidance to clarify legal requirements and reduce costs and complexity of pore space ownership and long-term liability.

In California there is a lack of legal clarity on geologic pore space ownership... While California law states that "the owner of land in fee has the right to the surface and to everything permanently situated beneath or above it.," the language is no longer interpreted literally.

Provide Certainty on Pore Space Ownership

While California law states that "the owner of land in fee has the right to the surface and to everything permanently situated beneath or above it,"[32,33] the language is no longer interpreted literally. Airspace provides an example of its anachronistic features.

Modern interpretations reflecting relatively new technologies would be instructive for informing issues of pore space ownership, where today's subsurface technologies are not accommodated in ways that airplanes, for example, have been, and where separation of mineral rights and surface ownership has further confused issues surrounding ownership of pore space.

In California, long-term CO_2 storage liability could be managed through a risk-sharing pool managed fully or partially by the private sector... The fund would require covered projects to follow all state and federal requirements. This approach offers an economically efficient mechanism to cover low probability, high severity events for all operators together, rather than require each operator to tie up sufficient capital to cover their own risk independently.

The lack of clarity of subsurface ownership complicates a scenario in which a CO_2 plume safely migrates into another location in the reservoir, forcing the project developer to seek additional access rights to avoid trespassing. California legislature should clarify pore space ownership, providing greater predictability for CCS operators. In the model adopted by Wyoming, Montana, and North Dakota, pore space ownership is vested with the surface owner.

A separate but related action would be for California to provide policy guidance for unitization agreements like the ones offered to oil and gas operators in California, whereby an entire field can be utilized for storage by a single operator with 75 percent of affected parties needing to consent.[34] States that have legislatively clarified pore space ownership have also adopted unitization frameworks (requiring 60 to 80 percent of landowners to consent).[35] Adopting a model similar to the other U.S. states with unitization frameworks for geologic storage could potentially limit the number of entities that must be compensated, especially for saline reservoirs that currently have little economic value.

Address Long-Term Monitoring and Stewardship Issues

Another critical issue that needs clarification is the management of long-term liability of stored CO_2. While there is evidence to conclude that stored CO_2 will remain permanently trapped (there has not been a recorded failure of caprock—among the most consequential incidents that could cause CO_2 to leak—in the U.S. since 1975),[36] an approach for overseeing management of stored CO_2 for decades to centuries is needed. Ensuring the safety and security of stored CO_2 is critical to the environment, public safety, and the CCS industry. The risks associated with building, operating, and closing geological CO_2 storage are known, are limited, and can be managed through familiar risk management frameworks by project operators. The minimal risks from CO_2 leakage could be reflected in updated requirements for site monitoring.

Management of long-term liability of stored CO_2 is a known barrier to CCS projects in California. First, there is limited flexibility to transfer or share the long-term monitoring and stewardship requirements for CCS projects, which are currently subject to EPA regulation of Class VI wells for geologic carbon storage. As described in detail in Chapter 4, the EPA's UIC program for Class VI wells requires post-injection site care (PISC) monitoring for 50 years after well closure and does not include provisions for the transfer of liability, essentially burdening CO_2 storage operators with the long-term liability for the storage site.[37] Also, PISC requirements for receiving LCFS credits—a critical revenue stream for many CCS projects in California—require an operator to care for the site for 100 years, twice as long as the federal requirement.

The assurances required to develop a CCS project in California—PISC for 100 years, financial obligations under LCFS, and the LCFS buffer account contributions of eight to 16 percent of the value of the LCFS credit—is significant relative to other infrastructure projects in the state. Recent studies, however, suggest the long-term risks of geologic storage projects are comparable to those for EOR operations, which have decades of successful implementation.[38] Aligning the requirements of the LCFS CCS Protocol with EPA UIC Class VI rules could reduce project costs, help standardize procedures between the state and federal requirements, and support closer alignment with industry and insurance standards.

Texas, Montana, and North Dakota provide limited liability and risk transfers to the state. In California, long-term CO_2 storage liability could be managed through a risk-sharing pool managed fully or partially by the private sector. In this model, each project developer would contribute funds to an account meant to cover the low probability, high cost catastrophic events associated with any single project. The fund would require covered projects to follow all state and federal requirements.[39] The fund could cover CCS projects across the country or only those that operate in California. The fund could be resourced in multiple ways to ensure it is not exposed to risks from a single source. Individual companies' LCFS Buffer Account contributions could be reduced commensurate with their verifiable contributions to an adequate industry-led fund.

Aligning the requirements of the LCFS CCS Protocol with EPA UIC Class VI rules could reduce project costs, help standardize procedures between the state and federal requirements, and support closer alignment with industry and insurance standards.

Another option could be the development of federal liability protections to accompany the Section 45Q tax credit. For example, the IRS could withhold a hypothetical mandatory contribution of $1/t$CO_2$ for each 45Q tax credit they award and devote this money to a government-managed insurance fund. Near-term resourcing for the insurance fund could come from state contributions or federal tax receipts, which could be paid back using the money collected from the withheld partial value of the tax credit, with interest.

Develop State Supported CCS Demos with Industry

Demonstration projects could provide valuable insights into the technical and regulatory challenges of a CCS project, reducing uncertainty associated with any new and untested process for project developers and regulators. The state should consider supporting large, state-sponsored CCS demonstration projects that could help overcome three major project barriers: high at-risk costs in the project's early stages; unclear and untested regulations

throughout the value chain; and lack of public acceptance of CCS. Box 5-2 details other state-level CCS demonstration projects in other countries.

BOX 5-2

EXAMPLES OF OTHER STATE-LED CCS DEMONSTRATION PROJECTS

Since the development of the **Sleipner** project in Norway in 1996, state-led CCS projects have paved the way for development of CCS technologies and value chains. The Sleipner project helped confirm many technical concepts associated with geological storage and monitoring and demonstrated successful compliance with Norway's regulatory regime.[40] Following on this success, the Norwegian government established the state-sponsored entity **Gassnova** to in 2005 to further the development of technologies and knowledge related to CCS and serve as the adviser to the government on this issue.[41] In September 2020, the Norwegian government launched the CCS initiative, 'Longship,' which will capture and store CO_2 from various industrial sources, including a cement facility and possibly a waste incineration plant.[42]

More recently, federal, and provincial governments in Canada have pioneered CCS projects with the aim of developing value chains. Hundreds of millions of dollars from Canadian governments were used in the construction of the **Alberta Carbon Trunk Line (ACTL)**, the largest-capacity pipeline specifically constructed for transport of anthropogenic CO_2.[43] With transport capacity of nearly 15 $MtCO_2$/yr, the pipeline is ready to accommodate many industrial operators on the upstream side; the downstream injection of ACTL CO_2 is handled by a private operator, which geologically sequesters the carbon while producing oil through EOR.[44] Separately, the **Quest CCS project**, funded largely by the Province of Alberta and the Canadian federal government, has demonstrated new technological efficiencies while successfully storing millions of tons of carbon dioxide.[45]

An ideal candidate site for a demonstration project would be located at or near suitable geologic storage, minimizing project costs and complexity by eliminating the need for CO_2 transportation. These demonstration projects could qualify for a CEQA exemption and the state could help overcome other permitting challenges. There is precedent for CEQA exemption for "New Construction or Conversion of Small Structures," such as for water main, sewage, electrical, gas, and other utility extensions, including street improvements, of reasonable length to serve such construction.[46]

Modeling conducted for this study shows that up to 5.6 $MtCO_2$/yr of emissions are from three ethanol plants, two CHPs, and five NGCCs located directly above suitable CO_2 storage. An additional 4.1 $MtCO_2$/yr from two CHPs and three NGCCs are within 10 miles of suitable CO_2 storage and would require minimal transportation infrastructure. These facilities would be ideal for demonstration projects. A lead agency—perhaps the newly appointed coordinating agency discussed earlier—could manage the projects in coordination with the industry developers. Data on the positive and negative results of the projects should be publicly available, providing valuable lessons learned for future projects.

Other demonstration projects could be initiated for large emitters, with a focus on projects that would preserve and grow the California workforce and target sectors for which carbon is difficult to abate with existing technologies. Due to the relative importance of gas-fired electricity generators, oil refiners, and cement manufacturers for the existing energy system and economy, the state should consider some of these facilities for demonstrating CCS. The state could prioritize projects that have demonstratable local air quality benefits and local job opportunities in line with its climate and equity goals.

KEY ENABLERS FOR ACHIEVING NET ZERO EMISSIONS

California policymakers should support key enablers to develop CCS at a scale sufficient to meet its 2045 target of statewide carbon neutrality.

Incorporate CCS Protocol into the State's Cap-and-Trade Program

As noted, CCS is currently an ineligible pathway under the Cap-and-Trade Mandatory GHG Reporting Regulation (MRR);[47] covered entities (electricity generators and industrial sources that emit more than 25,000 metric tons of CO_2 annually) cannot use CCS to reduce their compliance obligation (i.e. their annual emissions "cap"). In effect, there is no incentive for these covered entities to deploy CCS now or in years to come even though it could contribute large emissions reductions.

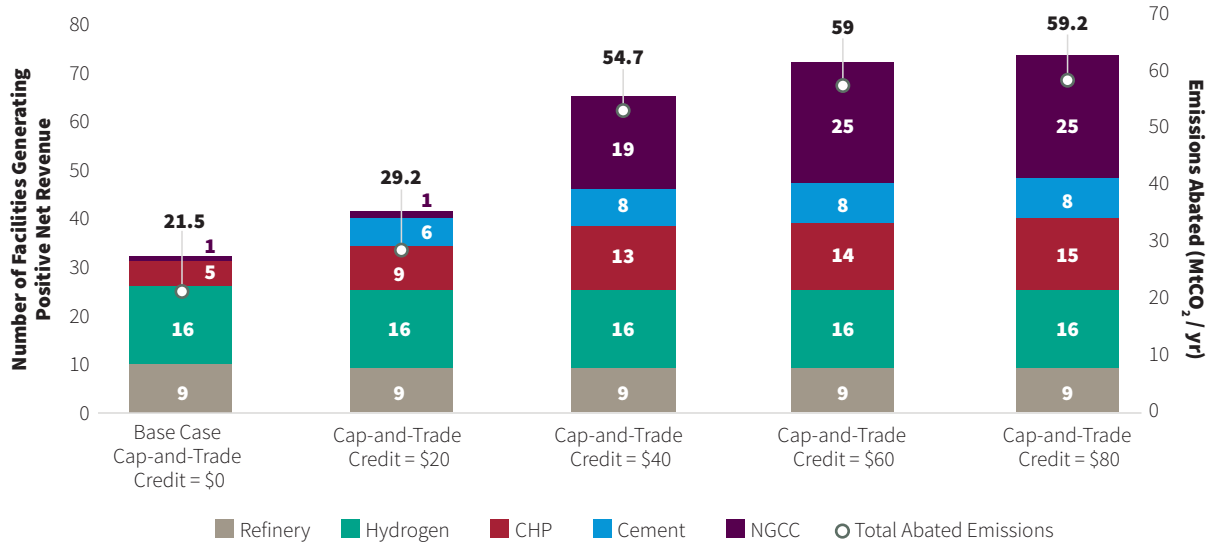
CARB should adopt the CCS Protocol from the LCFS program into the existing Cap-and-Trade Program. The existing CCS Protocol includes a number of important safeguards for CCS development, requiring that injection wells use the best available methods, the CO_2 storage zone is adequately studied, and long-term leakage risks are mitigated.[48] Incorporating the CCS Protocol into the LCFS enabled many transportation-related CCS projects to start early planning. Including it in the Cap-and-Trade Program could unlock even more opportunities for emission reductions, since the most difficult industrial emissions to abate, including cement, are covered by Cap-and-Trade, but are not eligible for LCFS credits.[49] This would help the state move closer to its carbon neutrality goal and help preserve California's strong industrial workforce and economy.

As seen in Figure 5-2, if a hypothetical credit under the Cap-and-Trade program[50] was applied to candidate facilities identified in the analysis in Chapter 3, six cement plants would generate positive revenues with a Cap-and-Trade credit of $20/tCO2 and a federal 45Q credit ranging from $35 to $50/t$CO_2$ depending on the disposal option. If the Cap-and-Trade credit is raised to $40, two additional cement plants and 19 NGCCs generate positive revenues, underscoring the importance of an additional incentive, especially for facilities like cement plants and NGCCS that are not eligible for the LCFS.

Also, as seen in Table 5-1, there is a differentiated effect given the implementation and value of a Cap-and-Trade credit. Ethanol, hydrogen production, refineries, and, to a large extent, CHPs are eligible to produce and sell LCFS credits, which accounts for a significant revenue stream, supporting meaningful IRRs.[c] However, the average cement and NGCC facilities would need to rely on a significantly larger Cap-and-Trade price to support CCS, given their LCFS ineligibility.

FIGURE 5-2

IMPACT OF A HYPOTHETICAL CAP-AND-TRADE CREDIT FOR CCS



A hypothetical Cap-and-Trade credit, when combined with 45Q and LCFS credits on eligible CCS projects, can incentivize greater CCS deployment and associated emissions reductions across various CCS applications. *Source: Energy Futures Initiative and Stanford University, 2020.*

c IRR is used to estimate the potential profitability of an investment.

TABLE 5-1

PROJECT IRR AS A FUNCTION OF CAP-AND-TRADE CREDIT

Cap-and-Trade Price ($)	Internal Rate of Return (%)					
	Ethanol	Hydrogen	Refinery	CHP	Cement	NGCC
$-	>15%	>15%	>15%	0-5%	0-5%	0-5%
$20	>15%	>15%	>15%	10-15%	0-5%	0-5%
$40	>15%	>15%	>15%	>15%	0-5%	0-5%
$60	>15%	>15%	>15%	>15%	>15%	10-15%
$80	>15%	>15%	>15%	>15%	>15%	>15%

This table shows the internal rate of return for a generic CCS project by source type as a function of Cap-and-Trade credit price with LCFS and 45Q incentives appropriately applied (i.e. all projects receiving 45Q; Cement and NGCC fully excluded from LCFS). *Source: Energy Futures Initiative and Stanford University, 2020.*

Improve Support Mechanisms to Make Projects More Attractive

Policies designed to reduce greenhouse GHG can be important tools for incentivizing industries to deploy CCS. Financial policy incentives must be designed to counter-balance deployment costs and help overcome the myriad technical, policy, and regulatory challenges that new CCS projects face. Most facilities technically suitable for CCS, including NGCCs for power generation and heavy industry (e.g. refining, cement, hydrogen production) operate in capital-intensive, heavily regulated sectors, that must often deal with thin operating margins and volatile commodity prices. As such, they generally seek long-term contracts, options, derivatives, and multi-lateral, liquid markets.

A major barrier in California to CCS projects for industries that are risk-averse with thin margins is the lack of near- and long-term *certainty* of revenues. Current policies that provide financial incentive for CCS—LCFS and 45Q—seem to have relatively high values; however, the existing design of these incentives limits their transformative potential. Also, CCS project financing challenges are exacerbated by the relatively high costs of FEED for CCS compared to capital investments with lower technology and regulatory uncertainty.

Support Early Projects with State Grants

FEED studies are important for demonstrating the technical feasibility of a project to potential investors and stakeholders. These studies are typically funded by the project developer prior to securing project financing for the entire project and can be a large financial barrier for particularly novel projects.

CCS projects face significant financing headwinds at the project onset; projects have uncertain permitting timelines, finite tax equity appetite, and competition with more widely deployed infrastructure projects. The state could reduce early stage CCS project financing challenges by providing funding support for FEED studies; this support should be provided to any in-state CCS project that would help decarbonize one of the state's largest emitting sources, demonstrate it will improve local air quality, and show that it will provide employment opportunities for existing workers in carbon intensive industries in line with the state's equity-focused policies.

Such support is not unusual. The U.S. DOE has historically funded FEED studies through cost-share agreements that have enabled several CCS projects to advance in development. In September 2019, the Electric Power Research Institute was one of nine recipients of DOE funding to conduct a FEED study for the CRC Elk Hills Power Plant project (described in detail in Chapter 2). In total, $55.4 million in federal funding was awarded to conduct FEED studies for commercial-scale carbon capture projects under the September 2019 Funding Opportunity Announcement.[51]

California could also consider providing startup grants for a certain portion of project funding. An example is a state grant program established to support its methane reduction goal: the Dairy Digester Research and Development Program (DDRDP) provides funding for the installation of dairy digesters to reduce methane

emissions from dairy manure.[52] DDRDP grant recipients must contribute 50 percent of the project costs, meet strict environmental criteria for air and water, engage in community outreach, and verify and report GHG emissions reductions from the project. DDRDP is funded through the California Climate Investment program, which uses Cap-and-Trade revenues for additional emissions-reducing projects in the state. Over the past four years, the California Department of Food and Agriculture has awarded $180 million, while projects have received $370 million in matching funds and are projected to reduce 20 $MtCO_2e$ over ten years.[53]

Seek 45Q Extension

While not in the control of the state, California's Congressional delegation could support an effort to reduce upfront cost barriers for CCS projects by supporting an extension of the revised federal 45Q tax credit. It will likely take as long as six years to develop and deploy a CCS project with a 20- to 30-year financing lifespan; the value of the 45Q tax is currently only available for less than half of the facility's operating years. Providing greater certainty for the availability of these credits beyond their current 12-year period could have a transformational impact on CCS project development.

A related issue is that to receive 45Q credits, project construction must begin by January 1, 2024. Project delays due to COVID-related financing issues and permitting challenges will make it difficult for some projects to begin construction in the next few years. Ideally, the timeframe required to begin project construction would be extended or the terms for receiving 45Q credits would be modified to consider these external factors that are likely to cause delays.

Extend, Clarify, and Revise LCFS

Modifications to the LCFS could have significant implications for CCS project developers. First, setting a price floor or other options to increase certainty in LCFS could provide CCS project developers with assurance of financial returns. Historical data show significant credit price volatility for the LCFS—in the last eight years prices have ranged from $25/t$CO_2$ to more than $200/t$CO_2$. This has made it difficult to anticipate future CCS project revenues. Ensuring stability in LCFS prices is critical, since LCFS credits are among the main financial drivers of CCS projects.

Second, the current LCFS CI target is lowered annually through 2030; it is presently uncertain if the CI targets will be reduced beyond the 2030 benchmark.[54] Clarifying LCFS CI targets through at least 2045 would improve long-term investor certainty. Governor Newsom's September 2020 executive order banning the sale of new internal combustion passenger vehicles in 2035 also adds uncertainty to the future of the LCFS.[55] Without longer term certainty of the availability of the LCFS credits, new CCS projects that rely on LCFS credit values are seen as high risk investments.

Finally, as noted, CCS projects seeking credits under the LCFS are required to contribute between eight and 16.4 percent of the credits they generate to a liability Buffer Account to protect against CO_2 leaks. This represents a significant share of the value of the LCFS credits. CARB could also develop an approach to periodically adjust the buffer account requirements for CCS projects that demonstrate safe and financially viable operations over time. This new approach could follow a clear, upfront schedule and assessment protocol, supporting a project's near- and long-term liability while also improving project returns.

Establish Public-Private Partnership for LA and Bay Area Hubs

This study identified clusters of emission-intensive facilities ("hubs") located in the Los Angeles Basin and the San Francisco Bay Area that are suitable candidates for CCS retrofit. These industrial regions tend to form around locations with ample energy supplies and transportation systems (e.g. ports, roads, pipelines). Developing CCS capture hubs where there is a high concentration of CO_2-emitting industries that could utilize the same CO_2 transport and storage infrastructure

could reduce transportation and storage costs for both the state and project developers. This could also help ensure the targeted, concentrated—and possibly more economic—development of a CCS industry compared to a proliferation of point-to-point projects. The state could prioritize projects that demonstrate local air quality benefits and provide local job opportunities in line with its equity commitments.

A recent analysis by the Great Plains Institute found that systems-level planning to midcentury (as opposed to near- and medium-term planning on a more localized scale) for the Central Region of the U.S. could result in nearly 2.4 times as much CO_2 stored, with marginal increases in capital investment, annual operations and maintenance spending, and miles of pipeline in the transportation network.[56] This highlights the benefit of planning at the regional or hub-level to meet midcentury goals, rather than on a project-by-project basis, to minimize infrastructure and cost requirements.

California should consider a state-supported public-private partnership that could manage the process for building out CCS hubs with shared transportation and storage infrastructure. An example of such a public-private partnership arrangement is described in Box 5-3, which details the Northern Lights CCS hub.

BOX 5-3

NORWAY'S NORTHERN LIGHTS CCS PROJECT

The Northern Lights consortium, consisting of Shell, Total, and Norwegian state-owned enterprises, aims to develop a CCS value chain covering transport and storage.[57] Following initial concepts and designs from Norway-owned CCS utility Gassnova, carbon transport and storage infrastructures are being developed to store 1.5 $MtCO_2$/yr starting in 2024, with capacity to be expanded to five $MtCO_2$/yr thereafter.[58] As of February 2020, geologic data have been collected from the test wells to identify candidate CO_2 storage sites.[59] Northern Lights aims to be the crux of a large-scale European carbon storage network.[60]

This map shows an overview of the Northern Lights CO_2 transport and storage network in Europe, which would provide centralized CO_2 storage off the coast of Norway for several emissions sources in the region. *Source: Equinor, 2020.*

The Bay Area and LA hubs would be ideal candidates for further FEED and/or feasibility studies. State sponsorship of these studies could reduce the financial burdens associated with initial development of CCS project. Modeling done for this study identified promising hub locations and potentially cost-effective capture, transport, and storage configurations. In the Bay Area, this included eight hydrogen plants, four oil refineries, and three NGCCs totaling 14 $MtCO_2$/yr. In the LA area hub, this includes eight hydrogen plants, five oil refineries, four CHPs, one cement plant, and five NGCCs totaling 25.2 $MtCO_2$/yr. Together, these proposed hubs could capture the equivalent of more than nine percent of the state's total GHG emissions in 2017.[61] As a reference point, it is also noteworthy that the hubs would account for 23 percent of the emissions reductions needed from 2017 statewide emission levels to the 2030 economywide goal.

Set Statewide Carbon Removal Targets

Studies show that reaching economywide carbon neutrality by midcentury or earlier is extremely difficult, if not impossible, without major contributions from CDR technologies that remove CO_2 from the atmosphere through technologically enhanced natural processes (e.g. carbon mineralization) and through DAC, and BECCS.[62] LLNL's "*Getting to Neutral*" report concludes that California will likely need to remove between 125-150 $MtCO_2$/yr from the atmosphere to reach its ambitious goal of economywide carbon neutrality by 2045.[63]

California is ideally suited to become a leader in CDR policy and technology development given its innovation capacity, skilled workforce in relevant sectors, ambition and progress on climate and clean energy policy, and its natural resource endowment. Evaluating and clarifying the role for CDR in the state's overall emission reduction portfolio will allow for faster and more purposeful development of technologies and policy frameworks to achieve those goals. CCS and some CDR pathways share key infrastructure needs, permitting processes, and geologic storage requirements, making the pursuit of either complementary to the deployment of the other.[64] California should begin laying the technical, legal, and policy groundwork to enable CDR to contribute to the state's emission reduction goals. Clearly, negative-carbon technology deployment will be necessary to eventually meet the economywide net-negative emissions objective.

Set Economywide Carbon Dioxide Removal Target

California's ambitious climate targets provide little guidance on the role for CDR and its critical role in meeting net-negative emissions. Executive Order B-30-15 and Executive Order S-3-05[65] set targets for economywide emissions reductions of 40 percent by 2030 and 80 percent by 2050 (from 1990 levels), respectively, and Executive Order B-55-18[66] requires economywide carbon neutrality by 2045 and net-negative thereafter. Setting a carbon removal target can help provide direction to state agencies to accelerate the development of new CDR projects that will be needed to achieve the B-55-18 goal.

Analysis of the state's future emission reductions has largely focused on the 40 percent reduction by 2030 and 80 percent reduction by 2050 targets. For example, CARB's 2017 Scoping Plan outlines a trajectory to midcentury that would be 86 $MtCO_2e$/yr short of carbon neutrality since it only considers the 80x50 target.[67] In light of the 2018 executive order calling for carbon neutrality by 2045, a multi-agency review of existing literature and consultation with experts could be used to set a CDR target.

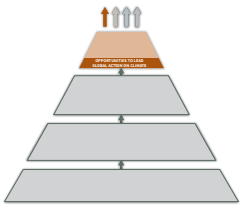
Multi-Agency Review of Eligible CDR Pathways

In 2019, the National Academies of Sciences published the report "*Negative Emissions Technologies and Reliable Sequestration: A Research Agenda*" outlining the potential role and value of CDR pathways to U.S. deep decarbonization.[68] This study was informed by a broad coalition of science and policy advisors who profiled the emissions reduction potential, estimated costs, safety and security concerns, and the long-term durability of the most prominent technological and technologically enhanced

CDR pathways. Also in 2019, the EFI report. *"Clearing the Air: A Federal RD&D Initiative and Management Plan for Carbon Dioxide Removal Technologies,"* presented a comprehensive portfolio for CDR research, development and demonstration (RD&D).[69] California could form a coalition, informed by the National Academies of Science process and include the LLNL team behind the "Getting to Neutral" report, to review the attributes of the major CDR pathways to determine appropriate selection criteria for California and develop a process for determining their eligibility to meet the state's established carbon removal targets. State agencies could be tasked with developing eligibility requirements for CDR pathways to align policies with emissions reduction potentials.

OPPORTUNITIES TO LEAD GLOBAL ACTION ON CLIMATE

CCS enables new clean energy pathways that create jobs and potentially multi-billion-dollar industries in California, such as clean hydrogen, CDR technologies, and carbon capture and utilization (CCU) industries. California has one of the most robust innovation infrastructures in the country and has the fifth largest economy in the world. The state should use its substantial resources and innovation capacity to support the demonstration and deployment of these new clean energy pathways through developing technologies, industries, and policies that could be replicated in other regions of the country and across the globe.



Support Innovation at Research Institutions & Laboratories

California should lead the global response to the climate crisis and catalyze a new clean technologies industry by breaking new ground with specific policy guidance for advanced clean fuels like hydrogen, advanced carbon removal systems including DAC and BECCS, and novel carbon capture and utilization technologies, all complementary to the core technology and infrastructure of CCS.

Support Hydrogen Innovation Programs

As California's energy system evolves and impacts from climate change grow, managing resilience and reliability of a low carbon system is challenging. As noted in Chapter 3, hydrogen can help overcome these challenges while providing significant economic value.

A promising option for developing new hydrogen systems is through regional hubs that include production and the supporting infrastructure for hydrogen storage and distribution. The hub-based model for creating early markets for hydrogen to drive scale and foster innovation was identified by IEA as a key near-term opportunity in the 2019 Future of Hydrogen report.[70] IEA also notes that hydrogen is already produced at refining and chemical facilities in industrial ports and that new sources of supply can be scaled to meet nearby shipping, trucking, and electricity demand. Industrial ports are often interconnected to the natural gas pipeline system, where even blending small proportions of hydrogen can drive production volumes and economies of scale. By creating shared infrastructure for using hydrogen produced from renewable generation and steam-methane reforming with CCS, the pace and scale of hydrogen deployment will be significantly advanced.

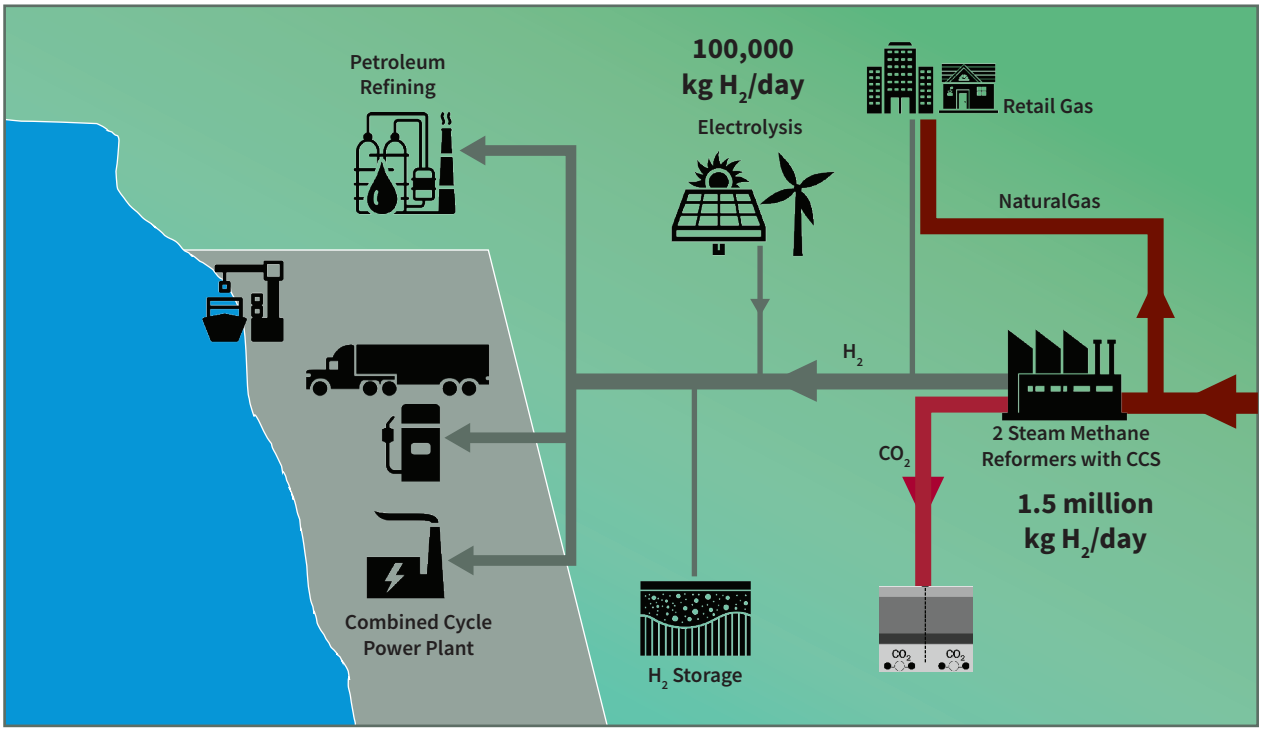
To accelerate the development of hubs that could serve as first movers and enablers of a larger self-sustaining hydrogen market, California could establish a "Hydrogen Hub Prize," a program that seeks actionable and scalable roadmap designs of hydrogen hubs from research institutions and laboratories. The winning plan would include workable designs for hydrogen production, transport, storage, and delivery to end uses. The plan should include a lifecycle emissions analysis. Project teams competing for the Hydrogen Hub Prize would need at least one significant participant/partner from a California research university or research lab participant.

Invest in Direct Air Capture Programs

The state already provides policy support for DAC technologies that remove CO_2 directly from the air instead of from concentrated point sources through eligibility for LCFS credits even though they do not produce a transportation fuel that is consumed in California.[71]

FIGURE 5-3

NOTIONAL HYDROGEN HUB AT THE PORTS OF LA AND LONG BEACH



One central steam methane reforming facility and one central electrolysis facility could supply half of the ports' drayage fleet (5,000 trucks); their entire electricity requirements (50MW/h); 80 percent of SoCal Gas' petroleum refiner demand; 10 percent of SoCalGas' residential gas demand (as blend); and CO_2 storage equivalent to half an average coal plant emissions. *Source: Energy Futures Initiative and Stanford University, 2020.*

The Buy Clean California Act may also provide new opportunities for DAC. The law requires the California Department of General Services to establish and publish procurement standards related to emissions for key construction materials, including structural steel and carbon steel rebar.[72] State agencies will be prohibited from procuring products with lifecycle emissions higher than the standards, though cement, concrete, and aggregate are not currently subject to the law.[73]

A major benefit of DAC is that capture facilities could be co-located with rural storage capacity. This will be especially important for managing project costs for DAC that currently have abatement costs significantly higher than point source capture. To address this and other issues associated with DAC, federal Fiscal Year 2020 appropriations provided DOE with $60 million for CDR technologies, including $35 million for DAC.[74]

An additional challenge of DAC is the high energy needs. According to one study, clean DAC requires approximately 700 MW of solar PV per $MtCO_2$/yr removed and a significant amount of land for both the DAC process and energy needs (about 1,700 acres for DAC and 4,900 acres for solar PV to remove one $MtCO_2$/yr).[75] California's research institutions could be incentivized to scale up innovation to reduce energy use and costs of DAC and address other issues, such as water and land usage.

California could commission a multi-user DAC research facility in California that would provide the state's research institutions a test bed for research on ways to reduce energy, water, and land use requirements. The test facility could be tasked with meeting certain performance targets for the DAC technology components. The results from the DAC test facility would be made public to support the technology's broader development. The state could also

support feasibility studies and demonstration projects focused on combining point source capture with DAC. This "hybrid" concept offers the potential to create process synergies. For example, the heat required for regeneration of the capture material in a DAC facility could be provided by the waste heat from the power generation or industrial facility. The hybrid concept could be explored further through a FEED study which, if shown to be feasible, could be implemented in a large-scale demonstration project. This is an important are of innovation as it could help an emitting facility achieve net zero carbon emissions and facilitate compliance with Cap-and-Trade or SB100. Combining point source carbon capture and DAC also could provide process synergies.

Support CO_2 Utilization Technologies

According to IEA, CO_2 utilization technologies could be scaled up to a market size of at least 10 $MtCO_2$/yr.[76] New pathways to use CO_2 are being developed to produce fuels, chemicals, and building materials. Over $1 billion has been spent on R&D for CO_2 utilization over the last decade.[77] While the near-term potential to develop new CO_2 industries remains small, the long-term prospect is significant especially in materials that currently rely on carbon for their structure.

CO_2 can be used to reduce the emissions footprint of California's cement industry, one of the state's most energy- and emissions-intensive industries. CO_2 gas could be turned into a solid aggregate to provide structure to the concrete using minimal energy.[78] CO_2 could also be used to cure concrete, resulting in a relatively high level of CO_2 stored in building materials, sidewalks, and other final products for many decades. California could incentivize research on CCU to propel the state's clean energy economy and set the stage for midcentury carbon neutrality.

Support Options to Ensure Adequate Clean Firm Power

Rolling blackouts in California in August 2020, the first since the California Electricity Crisis in 2000-01—have raised the public's concerns about grid reliability. In response to Governor Newsom's request for information on the causes of the blackout, CAISO sent a letter back to the Governor on August 19, 2020, that said, among other things, "Assigning definite causes to events on the electricity grid requires careful analysis...however, we do know a number of things already. We know that capacity shortfalls played a major role in the CAISO's ability to maintain reliable service on the grid.[79]

There are many technologies and market structures that contribute to system capacity and grid reliability, including firm generation. Since June 2019, however, 1926 MW of firm generation on the CAISO system was retired, with only 1500 MW added.[80]

While there is clearly a need for firm generation to ensure reliability, there is also a need for deep decarbonization, including decarbonization of the power sector. Studies show that both these objectives can be achieved by supporting policies to ensure the availability of clean firm power generation, which has significant value for cost-effective electricity system reliability under deep decarbonization scenarios.[d,81]

A recently completed study for California, for example, concluded that about 30 GW of clean firm generation would significantly lower the cost for achieving a zero emission grid. [82] This and other studies also conclude that CCS for natural gas combined cycle plants (NGCC-CCS) is one of the most cost-effective approaches for providing clean firm power generation. As described in Chapter 3, CCS on NGGCs can be deployed to help meet the 2030 emission reduction target for the electricity sector while ensuring that Californians have firm power when it is needed. However, as noted in Chapter 4, in September 2020, the California Energy Commission excluded CCS from its analysis of SB100 "due to insufficient cost data."[83]

d The U.S. EIA defines firm power as "power or power-producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions." Clean firm generation includes firm power resources that are low- or zero-emissions, including nuclear, geothermal, biomass, hydro, NGCC-CCS, hydrogen and other carbon free fuels using net-zero processes.

Developing these data and a more precise understanding of how much firm power is needed for a grid that is decarbonizing. This would inform grid reliability planning processes, identify key technologies for providing clean firm power in California, and provide guidance for developing policy options, including standards and mandates, for their scaleup and deployment – all essential for ensuring reliable, affordable, and clean power. Examples of technological options for clean-firm power include geothermal energy, nuclear power, NGCC-CCS, hydrogen with long term storage, renewable natural gas, and others.

California has extensive experience developing policy approaches for supporting deployment and scale-up of new energy technologies (e.g. renewable portfolio standards, energy storage mandate, low carbon fuel standard, cap-and-trade). Building on this experience, the state could identify and implement policies that would effectively support the scale up of clean firm power and ensure its availability. This could encourage utilities to procure clean firm generation resources at a level that would stimulate meaningful buildout of new capacity, and lead to future cost reductions, new industry development, and power system operational experience. The policy guidance should be technology neutral, allowing for any generation technology with zero- and near-zero lifecycle emissions. The policy could be replicated in other regions of the country, adjusted to meet local system needs and requirements.

These policies would not replace technology-neutral power sector emissions reductions policies like a clean energy standard. Instead, it would encourage incremental clean firm deployment where it is most likely to be used and useful in a deeply decarbonized power system, can be designed to be wholly compatible with existing power market and climate policy requirements in the state, and does not raise other significant policy concerns.

Create CO_2 Transport and Storage Operator

Building on the recommendation of large-scale demonstration projects, California should consider developing a new organization focused on coordinating the CO_2 transport and storage operations in a specific region or basin, leveraging state resources, such as lands and permitting authorities. The new organization could be modeled on other state entities that manage similar products and activities, like waste management and disposal, and could be a private or public entity.

This organization could be authorized to manage CO_2 transportation under bilateral contracts. Participating customers, such as oil refiners or natural gas-fired power generators, could engage through term contracts that set transparent rates (e.g. fixed or tied to commodity prices) and duration. These contracts would be used to pay for the operating and maintenance costs of the pipeline network. Another option would be for CO_2 transport to be handled with a common carrier model offering services to any potential user. In this case, it may need to be tied to a common CO_2 trunk line that supports one of the CCS regional hubs.

The CO_2 storage component could also be managed by a private or public entity. In either case, it should serve multiple customers. The customer rates could be used to support the physical operation of the storage resources and liability costs. Again, this model could be replicated in other states and regions that have established deep decarbonization goals and are considering CCS as an option for meeting these goals.

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Appendix A

Detailed Overview of CCS Permitting Processes in California

As discussed in Chapter 2, infrastructure permitting in California is an unquestionably important process to protect the state's land, water, air, and communities. This includes permitting at the local, regional, state, and federal levels. This appendix provides a detailed summary of key permits that may apply to CCS projects in California. As noted, because no two CCS projects are identical, the regulatory and permitting process is uncertain and challenging to navigate. This appendix also provides a State Comparison Table, which summarizes permitting authority and processes in other states pursuing CCS (Texas, North Dakota, New Mexico, and Wyoming) and compares them with California.

PROJECT DEPENDENT PERMITTING REQUIREMENTS

Permitting is not an exact science; projects come in unique forms, and thus it is incumbent upon developers to identify the scope of regulatory procedures to which they may be subject. As they pertain to environmental permitting, CCS projects have a plethora of permits that may apply to them depending on the extent of impacts from their construction and subsequent operation (Table A-1). Consulting with relevant permitting offices, agencies and other stakeholders before applying could save the developer time and resources in the long run, because they may learn a permit is not necessary for their circumstances. Additionally, doing so is a good practice for aligning expectations among the permitting agencies, CEQA lead, and developer before engaging in an often-lengthy process.

TABLE A-1

PROJECT DEPENDENT PERMITS FOR CCS PROJECTS

Permit Name	Program or Authority	Description	CA Permitting Agency [Industry]	CA Permitting Agency [Electricity, if dedicated CCS project)]
Section 404 Permit	Clean Water Act (CWA)	Under the CWA, a party must obtain a Section 404 permit from the U.S. Army Corps of Engineers (USACE) before discharging any dredged or fill material into waters of the U.S. General 404 permits are issued to common activities that arise in projects. Otherwise, an Individual Permit is issued, which requires a more thorough process.[1]	USACE	USACE
Federal Incidental Take Permit	Endangered Species Act (ESA) Section 10	If a species is listed in the California and Federal ESA, consultation between the California Department of Fish and Wildlife (CDFW) and U.S. Fish and Wildlife Service (USFWS) is required to determine which agency is responsible for authorizing the incidental take. It results in a 'Consistency Determination', which gives the Director of the CDFW 30 days to decide whether a federal permit suffices.[2]	USFWS	USFWS

Permit Name	Program or Authority	Description	CA Permitting Agency [Industry]	CA Permitting Agency [Electricity, if dedicated CCS project)]
Federal Right-of-Way	40 CFR 2800	A right-of-way from the U.S. Bureau of Land Management (BLM) grants the use of public land to another entity for the purposes of development. Development projects may include roads, pipelines, and transmission lines. The allowance is time limited and usually will extend for the lifetime of a project.[3]	BLM	BLM
National Pollutant Discharge Elimination System Permit (NPDES)	CWA	A NPDES permit is required if an entity discharges a pollutant from a point source to a surface water. The State Water Resources Control Board, along with its nine subsidiary Regional Boards, issue NPDES permits.[4]	California Regional Water Boards	CEC
California Incidental Take Permit	Fish and Game Code Section 2081	A state-issued Incidental Take Permit authorizes the "take" of an endangered, threatened, or candidate species if the take is incidental to otherwise lawful activity, the impact of the authorized take is mitigated, and adequate funding is available to do so.[5] Take, as defined by the ESA, refers to the harassment, harm, pursuit, hunting, shooting, wounding, killing, trapping, capture, or collection of the aforementioned species.[6]	CDFW	CEC
Lake and Streambed Alteration Agreement	Fish and Game Code Section 1602	The Lake and Streambed Alteration permit is required if an activity or project diverts/obstructs the natural flow of a river, stream, or lake, substantially changes any material from the bed, channel, or bank, or deposits debris, waste, and other materials containing crumbled pavement where it could pass into a river, stream, or lake.[7]	CDFW	CEC
California Coastal Development Permit (CDP)	State Coastal Act	CDPs are required when development occurs in a coastal zone. Development includes, but is not limited to: demolition, construction, clearing of vegetation, impeding access to recreational areas, altering property lines, or repair and maintenance activities.[8] Coastal zones extend seaward to the state's outer limit of jurisdiction and inland to specific points as designated by the California legislature. The exception for general CDPs is the San Francisco Bay, which is monitored separately by the San Francisco Conservation and Development Commission.[9]	California Coastal Commission	CEC
Prevention of Significant Deterioration (PSD) or New Source Review (NSR)	Clean Air Act (CAA) New Source Review (NSR)	If a major stationary emission source is constructed or undergoes major modification either an NSR or a PSD permit may be required prior to commencement of construction. If the source is located in an attainment area, PSD requires Best Available Control Technology to be determined from the source. If the source is in a non-attainment area, NSR requires Lowest Achievable Emissions Rate (LAER) to be determined for the source. In addition, both PSD and NSR permitting processes require air quality analysis, additional impact analysis, and opportunities for public engagement. The NSR/PSD permit may require revision of a facility's Permit to Operate (PTO).[10]	EPA Region 9	EPA Region 9

Permit Name	Program or Authority	Description	CA Permitting Agency [Industry]	CA Permitting Agency [Electricity, if dedicated CCS project)]
California Public Utilities Commission (CPUC) Regulation	Cal. Pub. Util. Code §§ 610 *et seq*	If there are large "trunk" pipelines collecting CO_2 from multiple sources, the CPUC may be able to assert "common carrier" jurisdiction over the entity which would otherwise control the pipeline. California law specifies that any person or corporation "providing transportation to or for the public or any portion thereof," meets the definition of a common carrier. That would subject the entity to public utility oversight.[11]	CPUC	CPUC
Joint Environmental Impact Statement (EIS)/ Environmental Impact Report (EIR)	California Environmental Quality Assessment (CEQA) and National Environmental Policy Act (NEPA)	When a project requires federal and state approvals, a joint EIS/EIR may be required (or Finding of No Significant Impact (FONSI)/Negative Declaration (ND) if there is no significant environmental impact). In this case, one state and one or more federal agency cooperate to reduce the duplication of any processes. In some cases, due to the divergence in expectations, the Lead Agency for CEQA may determine an EIR is necessary, while the NEPA lead agency decides there are no potential significant environmental impacts. When that happens, the agencies write a joint Environmental Assessment (EA)/EIR with an explanation of why the federal agency determined no potential significant environmental impacts.[12,13]	Situational (one state & one federal agency)	CEC and Relevant Federal Agency
Local Conditional Use Permit (CUP)	California Constitution Article XI, Section 7	A CUP allows a city or county to consider special uses of its land that may be favorable to the community but are not allowed within a zoning district. The project or development is proposed in a public hearing setting, and if it is approved, it allows flexibility within the zoning ordinance with stipulations. The CUP is subject to CEQA, which may lead to an EIR before a public hearing can occur.[14] The project must also fit in the context of a city or county's general plan, which lays out the long-term plan for the community.[15] Sometimes, developers will apply for a general plan amendment instead of a CUP. The process of applying for an amendment is similar to a CUP, with CEQA requirements and a public hearing established in the application review procedures.[16]	Cities or Counties	CEC

This table details the situation dependent permitting processes and applications that could be required for a particular CCS project in California, depending on its exact location and characteristics. *Source: EFI and Stanford, 2020.*

Permits with Federal Oversight

The Clean Water Act (CWA) requires parties to obtain a Section 404 permit from the U.S. Army Corp of Engineers (USACE) if there is evidence of potential dredge discharge or fill materials into waters of the U.S.[17] USACE tiers their permits into general and individual levels to potentially expedite the process if an activity is relatively common.[18] If a permit is general, the process to receive a permit is typically 60 days. If it is an individual permit, the permitting procedure may take 180 days or more and includes public input to guide the final decision.[19] Furthermore, in instances where the project takes place in a coastal area of California, a Consistency Determination is needed in order to complete a 404 permit.[a,20]

The United States Fish and Wildlife Service (USFWS), through the Secretary of Interior, issues permits for the incidental take of endangered species and wildlife at the federal level.[21] In coordination with USFWS throughout the process, a developer is responsible for creating a Habitat Conservation Plan (HCP). The requirement means an applicant must design, implement, and fund a conservation plan for the area they are seeking to utilize for the proposed project. HCPs include a draft EIR/EIS, if it is required, alongside application fees and an agreement on implementation of the activity. When an HCP is deemed complete, the USFWS allows up to 90 days to receive public comment on all aspects of the HCP, including the EIR/EIS.[22] For a project with low effect, the comment period can be shortened to 30 days.

For projects intersecting federal land, a right-of-way grant must be issued by the Bureau of Land Management (BLM).[23] Applications for grants are coordinated through regional BLM field offices; following a pre-application meeting to discuss a proposed project, developers must submit an application containing detailed project descriptions, maps, statements of technical and financial capability, as well as alternatives to the project.[24] Upon receipt of application fees, agreements are typically processed within 60 days, subject to the availability of BLM specialists to verify application claims.[25] Right-of-way grants issued under the Federal Land Policy and Management Act may last for ”a reasonable term,” which could be in perpetuity, or may be subject to reissuance depending on monitoring protocol.[b,26]

Permits with State Oversight

While the National Pollutant Discharge Elimination System (NPDES) is a federal permit authorized under the Clean Water Act (CWA), the decision-making authority is held by California’s nine Regional Water Boards, which oversee the state’s rivers, streams, lakes, wetlands, ocean, and groundwater[27] NPDES *(also referred to as Waste Discharge Requirements)* is needed in any case where a pollutant is discharged from a point source to surface water.[28] Issuance of NPDES permits typically takes around six months with designated periods of time for public input.[29]

California similarly has its own incidental take permit sequencing authorized under the California Department of Fish and Wildlife (CDFW).[30] If an operator has already obtained a federal incidental take permit, however, it is not always necessary to complete the California incidental take permitting process. Instead, the project applicant notifies the director of CDFW and provides a copy of the federal incidental take permit granted by the USFWS.[31] The CDFW director then has 30 days to decide whether the federal permit is consistent with California code. If not, a new application process is opened to comply with state requirements that could take up to 120 days to approve from an application’s submission to the CDFW.[c,32]

CDFW also issues Lake and Streambed Alteration Agreements, which are necessary for activities that substantially affect bodies of water[33] Developers are required to provide written notification of an activity that could substantially affect bodies of water to CDFW. CDFW then determines if a Lake and Streambed Alteration Agreement is needed within 30 days of receiving a

a Consistency Determinations are required when a development project will affect the land or water uses in a California Coastal Zone and federal permitting is involved in regulating the project.

b Projects involving oil or natural gas would be subject to the Mineral Leasing Act, which has different approval criteria; however, a project purely involving CO_2 transport rights-of-way would be governed under the Federal Land Policy and Management Act.

c The timeline is a function of CDFW being the responsible agency versus the lead. If they are just the responsible agency, the timeline could be shortened to around 30 days instead.

complete notification. If the activity is deemed potentially substantial by CDFW, the CDFW may require an onsite inspection, which will inform their draft agreement with the applicant.[34] The CDFW is required to issue a draft final agreement to the developer within 60 days, and if they do not, the developer can proceed with the project specified in the notification.[35] When both parties agree to all tenets of the project, CDFW can issue a final agreement, which will be the document that guides the developer's work.[36] A final agreement cannot be issued until a CEQA EIR or EIR/EIS is completed by the lead agency.[37]

If a project takes place in a California coastal zone, California Coastal Development Permits (CDPs) may be required for some onshore development activities, beyond the consistency requirements already mentioned. The California Coastal Commission (CCC) regulates the use of land and water in coastal zones. California Coastal Development Permits (CDPs) may be required for some onshore development activities, beyond the consistency requirements already mentioned. Once a CPD application is submitted, the CCC has 49 days to schedule an application for a decision at a public meeting, which are held monthly. Included in the application are CEQA documents and other relevant materials. It is important to note that the San Francisco Bay has its own permitting process in place of the CCC CPD permitting process.[38]

Under the Clean Air Act (CAA), EPA sets national ambient air quality standards (NAAQS) for a set of six criteria air pollutants[d] that states must comply with through their State Implementation Plans (SIPs).[39] States' CAA compliance is based on local ambient air quality attainment or nonattainment of those NAAQS, not necessarily on the volume of pollutants emitted from a given point source.[40] However, if major sources[e] of air pollution or emissions make "major modifications" to their facilities, then the CAA triggers a New Source Review (NSR) which requires the installation of Best Available Control Technology (BACT) in attainment areas or Lowest Achievable Emissions Rate (LAER) in nonattainment areas. NSR applies separately to each NAAQS pollutant emitted by a major stationary source.[41] The CAA as amended requires that only changes which result in an increase of emissions of a given pollutant will be considered "major modifications." It further establishes that the addition of a system whose "primary function is the reduction of air pollutants" shall not be considered a modification for the purposes of triggering NSR.[42] Increase in emissions for power plants has been interpreted by the Supreme Court to include an increase in operating hours per year that is foreseeable due to the modification (ie increased heat rate leading to more competitive dispatch in a power market). However, there is no definitive guidance on whether the addition of CCS systems would count as a "major modification". It is possible that the installation of a CCS plant could lead to an increase in air pollutants other than CO_2 (i.e. a power plant may emit more criteria air pollutants by generating more electricity, thus increasing the CCS parasitic load). If that is the case, then a facility possessing a Title V operating permit for being a major source of air pollutants may have to undergo significant revisions of that permit.[43]

Finally, the California Public Utilities Code grants the power of eminent domain to utilities operating in the public interest; a hypothetical owner and operator of a CO_2 pipeline would qualify as a pipeline corporation,[44] thereby enabling their use of eminent domain to secure pipeline transport routes.[45] Eminent domain takings would require public hearings open to members of the public in the jurisdictions through which the pipelines would pass, in which a commissioner or administrative law judge would assess the necessity and public good of the proposed takings.[46] If the project satisfies those requirements and passes environmental review, eminent domain may be exercised.

d The six criteria air pollutants are: carbon monoxide, lead, ground-level ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. In *Massachusetts v. EPA* (U.S. 2007) the Supreme Court ruled that EPA has the authority to regulate CO_2 as an air pollutant, but CO_2 is not generally considered a criteria air pollutant and no NAAQS has been set for it.

e "Major sources" are defined in Section 112 of the Clean Air Act as stationary sources or groups of sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant, or 25 tons per year of a combination of hazardous air pollutants.

Joint State/Federal Permitting (CEQA & NEPA)

As mentioned in Chapter 2, typically if a federal agency is involved in an aspect of CCS permitting, the project is subject to both CEQA and NEPA consultation.[47,f] An exception is for UIC Class VI well permitting, which qualifies for a categorical exemption from NEPA.[48] A 'project' is broadly defined as any public or private activity which may have a significant impact on the environment. For CCS projects, the definition includes all components of capture, transport, and storage.[49,50] Since CCS projects have the potential to span many miles and involve numerous local, state, and/or federal jurisdictions, issues of regulatory involvement and responsibility become especially complex but NEPA and CEQA are likely to both be triggered.

While there is overlap between CEQA and NEPA, the differences are notable and may present greater challenges to developers that are required to complete both CEQA and NEPA. For instance, under CEQA, an EIR is required if there is substantial evidence that "supports a fair argument" a project might have significant impact(s), despite competing substantial evidence suggesting otherwise. In that case, an EIR would be prepared. Conversely, NEPA may look at that same circumstance and decide only an Environmental Assessment (EA) is necessary, which requires much less analysis. Definitional and procedural differences likely require frequent collaboration between the federal and state or local lead agencies.[51] Procedural differences are shown in Table A-2. Finally, a key difference between CEQA and NEPA is that CEQA requires that a project applicant not only evaluate all significant environmental impacts but also mitigate impacts to the extent feasible. NEPA does not require mitigation, only consideration of impacts.

TABLE A-2

COMPARISON OF EIS AND EIR PROCESSES AND TERMINOLOGY[52]

NEPA Environmental Impact Statement (EIS)	CEQA Environmental Impact Report (EIR)
Notice of Intent	Notice of Preparation
Scoping	Scoping
Draft EIS	Draft EIR
Filing with EPA which publishes a Notice of Availability for the draft in the Federal Register	State Clearinghouse Distribution for State Agency Review
Public and Agency Review and Comment	Public and Agency Review and Comment
Final EIS	Final EIR
	Provide proposed responses to public agency comments at least 10 days prior to certification of the EIR
Filing and EPA Notice of Availability in the Federal Register, Public and Agency Review (if designated)	Certify EIR, adopt Findings on Project's Significant Environmental Impacts and Alternatives, Mitigation Monitoring and Reporting Program, and, if necessary, a Statement of Overriding Considerations
30 Day Review Period	
Agency Decision	Agency Decision
Record of Decision	Notice of Determination

f Any project extending into federal land, impacting federal waters, impacting federally designated endangered species, etc. involves certain federal agencies in permitting.

In addition to mandated consultation - known as scoping in federal proceedings – there are circumstances that call for a joint Environmental Impact Study (EIS)/EIR, should the lead agency be at the point of drafting the EIR before a federal agency completes an EIS. The CEQA lead can work alongside the federal lead agency to complete the joint document, rather than having two separate documents filed. It is important, however, that the federal agency is involved in preparing the joint EIS/EIR, because it is illegal for a federal agency to use a state EIR in which it was not involved.[53] Often, the CEQA lead and federal agency enter a Memorandum of Understanding to ensure all requirements are met. While these formalities may strengthen the cohesiveness of a joint CEQA/NEPA approval process, it also has the potential to lengthen the time of review as more entities become intimately involved in the process. In fact, the lead may waive the one-year time horizon for completing and certifying a final EIR in the circumstance of federal involvement.[54] For a private project, it would otherwise be required that the lead certify the final EIR within a year.[55]

Local Land Use Regulations, Zoning, and CEQA

California is comprised of 58 counties and 482 incorporated cities, each with distinct government entities in charge of decision-making.[56] Codified in the California Constitution, local governments have the authority to oversee local planning and land use regulations for the betterment of their community.[57] As is required by state law, they each have established long-term general plans for that jurisdiction's development of land. The general plan is used to describe the city or county's future development, rather than providing specific standards of the current development. That responsibility belongs with zoning ordinances, although those too must fall in line with the policies described in the general plan.[58] A CCS project might either require a General Plan Amendment, known as a Specific Plan, or a Conditional Use Permit in order to comply with local land use regulations.

A Specific Plan amends the General Plan to create an area within a community subject to its own distinct land use and development goals and objectives, such as siting of CCS. A Conditional Use Permit (CUP) provides an exception to zoning ordinances to provide flexibility for a project that may be special or unique, such as CCS. Specific Plans and CUPs are subject to CEQA, like any other state or local permit. Before a public hearing is held to determine if a Specific Plan or CUP will be approved, the city or council first determines whether the project may have environmental impacts. If the project is not exempt from CEQA because of potential environmental issues, the city or county must provide a Negative Declaration (ND), or Environmental Impact Report (EIR) as described by CEQA. In those cases, the process to obtain a Specific Plan or CUP may become quite lengthy.[59] In either case, the Specific Plan must either render the General Plan consistent with the project or CUP must be in line with the general plan of that city or county. If not, general plan amendments may be needed to proceed with project development.[60]

COMPARING CALIFORNIA REGULATIONS WITH THOSE OF OTHER STATES PURSUING CCS

Chapter 4 articulated permitting and regulatory challenges, while Chapter 5 presented options for policymakers to address some of the barriers to CCS development in California today. As a reference to policymakers developing new policy for California, Table A-3 compares jurisdictional oversight and regulations in four states to California's. While every state's ideal mix of CCS policy differs, certain states offer compelling models that could be implemented in California.

TABLE A-3

STATE COMPARISON TABLE

		Texas	North Dakota	New Mexico	Wyoming	California
Storage Permitting	**Agency Jurisdiction: Class II Wells**	Railroad Commission[61]	North Dakota Industrial Commission[62]	New Mexico Oil Conservation Division[63]	Oil and Gas Conservation Commission[64]	California Geologic Energy Management Division (CalGEM) OR CEC[65]
	Agency Jurisdiction: Class VI Wells[66]	EPA	North Dakota Industrial Commission[67]	EPA	Wyoming Department of Environmental Quality[68]	EPA
Post-Closure Site Care and Liabilities	**Class VI Post-Injection Site Care Requirements**	Regulated by EPA Region 6; follows EPA 50-year mandate[69]	Primacy: state can assume ownership after closure no earlier than 10 years.[70] Owners of active wells must pay into state-run CO_2 Storage Facility Trust Fund to cover long-term monitoring costs.[71]	Regulated by EPA Region 6; follows EPA 50-year mandate[72]	Primacy: Post-injection site care shall be for a period of not less than 10 years[73]	Operator monitors for 100 years with updates every 5 years for Class VI wells to obtain LCFS Credit:[74] EPA 50 years mandate otherwise
	Class VI Well Long-Term Liability	Under the Safe Drinking Water Act and according to EPA guidance, Class VI well closure does not necessarily release owners from future liability under tort or federal statutes including but not limited to CAA, CERCLA, and/or RCRA.				
Pipelines & Transportation	**Primary State Agents**	Railroad Commission[75]	Public Safety Commission (PSC)/ Private Landowners/ Local Governments[76]	New Mexico Public Regulation Commission Pipeline Safety Bureau[77]	Wyoming Energy Authority (WEA)[78]	California Air and Resources Board (CARB)/State Fire Marshal/Local Governments/Private Landowners[79]
	Right of Way (ROW)	Pipeline authorization is easy due to eminent domain power of oil and gas companies. Regulation runs through the Railroad Commission.[80]	Oil and gas companies use voluntary easements as opposed to eminent domain. North Dakota has the 'most restrictive laws in the nation on land acquisition'.[81,82]	Any person, firm, or corporation may use eminent domain to acquire the necessary ROW.[83]	WEA is working in partnership with the BLM to scope out up to 2,000 miles of pipeline designated for carbon storage/ EOR. The WEA has authority of eminent domain.[84]	Negotiations with local and private interests can be long and complicated, and oil and gas companies possess minimal leverage. The State Fire Marshal has jurisdiction over pipeline operations once in place.[85]
Water Permitting	**Primary State Agents**	Texas Commission on Environmental Quality[86]	Division of Water Quality in the Department of Environmental Quality[87]	New Mexico Environment Department[88]	Wyoming Department of Environmental Quality[89]	Department of Fish and Wildlife (DFW)/ Regional Water Boards[90,91]
Air Permitting	**Primary State Agents**	Texas Commission on Environmental Quality[92]	Division of Air Quality in the Department of Environmental Quality[93]	New Mexico Environment Department	Wyoming Department of Environmental Quality[94]	35 Local Air Districts (for industry)/CEC (for thermal power plants)[95]

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Appendix B

Supplementary Information and Assumptions for Electricity Grid Modeling

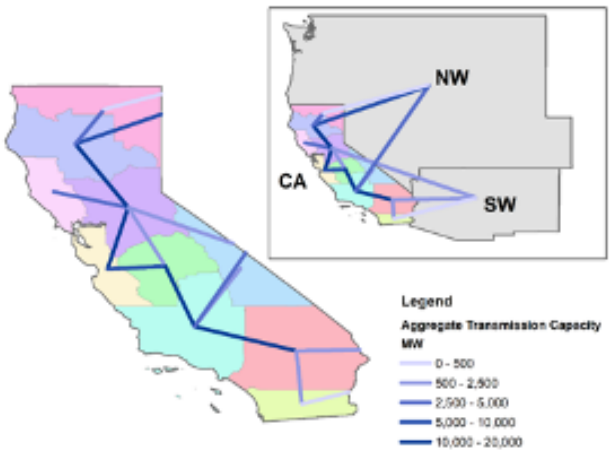
INTRODUCTION AND MODEL ASSUMPTIONS

For this study, a capacity expansion and dispatch model, *urbs*,[1] for the California grid was utilized to assess what role CCS might play in meeting California's SB100 goals in 2030. The model finds the lowest cost combination of new technology builds and their respective operating schedules to simultaneously meet hourly electricity demand and policy goals. The model simulates operation throughout all 8,760 hours of the entire year. The modeled California system includes 10 regions in California and two additional out-of-state regions (Figure B-1). The two out-of-state regions are modeled to represent California's interaction of both specified, and unspecified imports and exports with regions outside of California.

The model optimizes the system for 2030 based on the 2018 electricity system in California.[2,3] Cost estimates, financial assumptions, and expansion potential for generation technologies and storage are taken from the California Public Utilities Commission's (CPUC) 2019 Integrated Resource Planning (IRP) process as summarized in Table B-1.[3] Cost and operational assumptions for NGCC power plants retrofit with CCS are based on NETL's Fossil Fuel Baseline analysis and are summarized in Table B-2.[4]

FIGURE B-1

URBS MODEL SET UP FOR CALIFORNIA



The urbs model set up has 10 regions for in-state California and two regions out-of-state. Each region in the model has a distinct load profile and PV and wind generation profiles. *Source: Energy Futures Initiative and Stanford University, 2020.*

TABLE B-1

CAPITAL COST AND FIXED O&M COST FOR GENERATION AND STORAGE RESOURCES MODELED

	Average Capital Cost 2020-2030 [$/kW]	Average Fixed O&M Cost 2020-2030 [$/kW-yr]	Variable Cost	Available Max. Expansion Capacity [GW]
PV	$880/kW+10% ITC[a]	$7	-	+ Inf in-state + 2 GW OOS
Onshore Wind	$1,480/kW+PTC[b]	$48	-	+ 2 GW in-state +2.5 GW OOS
Offshore Wind	$4,370/kW+30% ITC	$89	-	+16 GW[5]
Li-ion Batteries (4 hour duration)	$220/kWh+10% ITC	$3/kWh	-	+ Inf
Biomass	$4,800/kW	$110/kW	$2/MMBtu[c]	+1.2 GW
Geothermal	$5,120/kW	$145/kW		+2.2 GW
NGCC-CCS retrofit	$890/kW	$45/kW	See Table 2	Retrofit Only +13 GW

TABLE B-2

MODEL ASSUMPTIONS FOR NGCC-CCS

Description	Value
CO_2 Capture Amount	0.3 tonne/MWh
CO_2 Emissions	0.03 tonne/MWh
Heat Rate	7159 Btu/kWh
Ramp Rate*	0.5
Fuel Cost	$5.9/MMBtu
Variable O&M	$0.25/MWh
45Q Tax Credit ($50/tonne)	$15/MWh
Storage and Transportation Costs** ($15/tonne)	$32/kW

*Ramp rate indicates percentage of capacity that can be ramped up or down in a given timestep (1 hour)
**converted to $/kW assuming an 80% capacity factor

California is expected to have high levels of electrification in both the transportation and building sector. Baseline load growth assumptions and energy efficiency gains are taken from CPUC's 2019 IRP process.[6] In addition to the baseline load growth, the analysis assumes further load growth from building electrification (assume California is on path to electrify 90 percent of its existing residential buildings by 2045) and electrification of five million light duty vehicles per Executive Order B-48-18 (Table B-3). Due to the growth in building electrification, California's winter load increases significantly, but remains a summer peaking system (Figure B-2). The load for each region is taken to be proportionate to the population within each region. Additionally, 17 GW of behind the meter distributed PV and 1.6 GW of behind the meter storage is modeled within the system to meet the increased load.

TABLE B-3

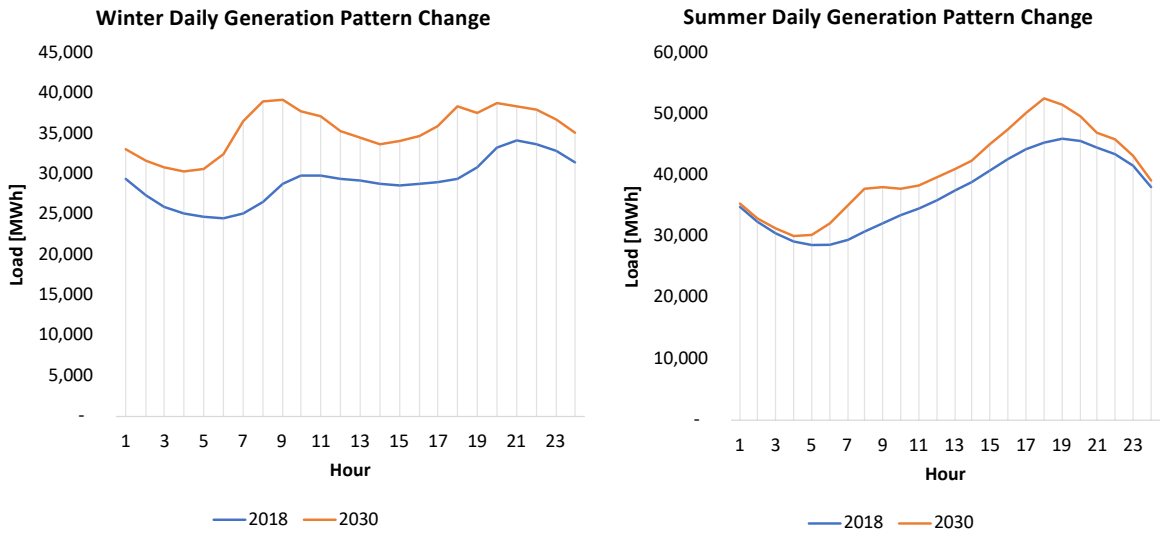
LOAD GROWTH ASSUMPTIONS IN 2030[7]

Year	Load Assumptions
2018	276 TWh (59 GW peak)
2030	317 TWh (65 GW peak) Including 5 million EVs Including 50-60% electrification of existing residential buildings

a ITC = Investment Tax Credit
b PTC = Production Tax Credit
c $2/MMBtu for Woody Fuel; 13,500 Btu/kWh Heat Rate; $5/MWh Variable O&M

FIGURE B-2

AVERAGE DAILY LOAD GENERATION PATTERNS IN 2018 AND 2030



Due to building electrification, there is a significant growth in winter load, and moderate growth in load in the summer. From 2018 to 2030, the daily load shapes are shifted in the winter with higher loads in the morning and evening hours, but remain relatively consistent in the summer. *Source: Energy Futures Initiative and Stanford University, 2020.*

California's SB100 policy mandates a 60 percent RPS goal by 2030, and California's Long-Term Energy Scenarios project conducted by the California Energy Commission (CEC) has indicated the need for the electricity sector to reach 32 $MtCO_2$ emissions by 2030 to meet its SB32 economywide emission reduction goals.[8] Considering the electricity sector's important role in decarbonizing the economy, a 32 $MtCO_2$/yr emissions constraint, in addition to a 60 percent RPS, is considered for the electricity sector in this analysis.

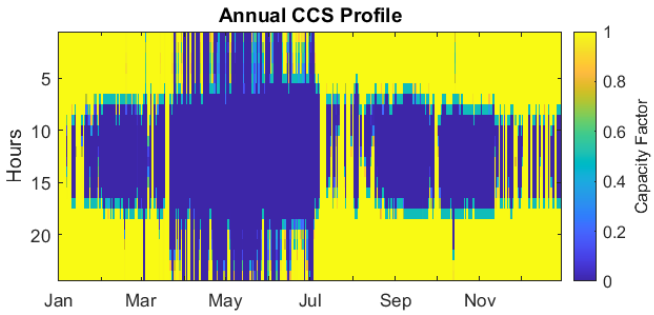
California's annual system costs are inclusive of annualized capital costs of building new generation and storage resources, annual O&M costs, annual fuel costs, annual net import/export costs, and annualized spur line costs for new generation resources. Annual net import/export costs are calculated using the marginal cost of generation and import/export amount at the time of California's exchange with NW and SW regions. Spur line costs are assumed to be $3,670/MW-mi (2013 USD, $3,960/MW-mile in 2018 USD) in WECC, and x2.25 that cost in California.[9] We further assume an average spur line distance of 12 miles and annualize the capital costs using a capital recovery factor of 7%.[d] Spur line costs are added for new geothermal, wind, and solar capacities. A reliability multiplier of 1.6 is considered for new geothermal capacities based on assumed need for double-circuit lines.[10] Spur line costs for new CCS capacities are not considered due to existing spur lines at the site of retrofit. Note the annual system cost does not include distribution or transmission system developments needed and associated costs in 2030.

The development of California's grid between 2018 and 2030 is largely driven by the growth in load and meeting the 60 percent RPS and emission reduction goals. The electricity system model finds that 4.2 GW of NGCC-CCS is cost-optimal and approximately $750 million cheaper than the scenario without any NGCC-CCS. Based on the growing PV capacity in California, retrofit NGCC-CCS in 2030 operates flexibly both annually and diurnally (Figure B-3) to complement the PV generation. NGCC-CCS operates largely during night-time when PV is not available, as well as during the wintertime when seasonal PV generation is low.

d 6.7% WACC and 40 year financial lifetime for spur lines

FIGURE B-3

ANNUAL GENERATION PATTERN OF RETROFIT NGCC-CCS IN 2030



This figure shows the annual generation profile of CCS. CCS largely operates during the night time and in the winter time when PV generation is low. *Source: Energy Futures Initiative and Stanford University, 2020.*

BOX B-1

FLEXIBLE OPERATION OF NGCC-CCS

As California grows its share of intermittent renewable resources to meet its SB100 goals, NGCC-CCS in California will likely have to operate flexibly within the grid. Existing data from pilot-scale solvent-based NGCC-CCS plants indicates that flexible operation of NGCC-CCS plants is possible by optimizing plant operation by varying solvent flow rate, composition, circulation times, capacity and more [11]. The pilot-scale experimental studies also indicate that there is room for improvement in flexibility by optimizing plant design or utilizing solvent storage that allow CO_2 capture levels to remain constant while varying electricity output.[12] CO_2 capture with membrane separation systems and NGCC-CCS with oxy-combustion systems have also been considered suitable candidates for increased flexible operation.[13]

Another method for NGCC-CCS to operate flexibly within the grid is for the plant to provide other services outside of the grid, such as capturing and utilizing CO_2 for enhanced oil recovery or converting excess electricity to hydrogen via electrolysis.

The challenge of flexible operation will be to balance incremental capital and operational costs of achieving flexibility with the additional revenue opportunities from increased flexibility.[14] Furthermore, in addition to plant-level flexible operation, NGCC-CCS power plants will also need to take the flexibility of downstream operations, such as compression, transportation, and storage, into consideration.

Endnotes

1 Dorfner, "Urbs: A Linear Optimisation Model for Distributed Energy Systems"; Siala et al., "Towards a Sustainable European Energy System: Linking Optimization Models with Multi-Regional Input-Output Analysis."

2 Environmental Protection Agency (EPA) 2020 Emissions & Generation Resource Integrated Database (eGRID) - eGRID 2018 US EPA Online: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid

3 California Public Utilities Commission, "RESOLVE Model and Preliminary Results Used for 2019 IRP Portfolio Development."

4 Fout et al., "Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3."

5 Musial et al., "Potential Offshore Wind Energy Areas in California: An Assessment of Locations, Technology, and Costs."

6 Kavalec et al., "California Energy Demand 2018-2030 Revised Forecast"; California Public Utilities Commission, "RESOLVE Model and Preliminary Results Used for 2019 IRP Portfolio Development."

7 Kavalec et al., "California Energy Demand 2018-2030 Revised Forecast"; California Public Utilities Commission, "RESOLVE Model and Preliminary Results Used for 2019 IRP Portfolio Development."

8 California Energy Commission, "Deep Decarbonization in a High Renewables Future."

9 Cohen et al., "Regional Energy Deployment System (ReEDS) Model Documentation : Version 2018 Regional

10 Juan Andrade and Baldick, "Estimation of Transmission Costs for New Generation."

11 Tait et al., "A Pilot-Scale Study of Dynamic Response Scenarios for the Flexible Operation of Post-Combustion CO2 Capture"; Gaspar et al., "Dynamic Operation and Simulation of Post-Combustion CO2 Capture"; International CCS Knowledge, "The Shand CCS Feasibility Study Public Report."

12 Chalmers et al., "Flexible Operation of Coal Fired Power Plants with Postcombustion Capture of Carbon Dioxide"; Arce et al., "Flexible Operation of Solvent Regeneration Systems for CO2capture Processes Using Advanced Control Techniques: Towards Operational Cost Minimisation"; Bui et al., "Dynamic Modelling and Optimisation of Flexible Operation in Post-Combustion CO2 Capture Plants-A Review"; Mac Dowell and Shah, "The Multi-Period Optimisation of an Amine-Based CO2 Capture Process Integrated with a Super-Critical Coal-Fired Power Station for Flexible Operation."

13 Yuan et al., "Design and Operations Optimization of Membrane-Based Flexible Carbon Capture"; Hume et al., "Improving Flexibility and Performance of Staged Pressurized"; Tranier et al., "Air Separation, Flue Gas Compression and Purification Units for Oxy-Coal Combustion Systems."

14 Yuan et al., "Design and Operations Optimization of Membrane-Based Flexible Carbon Capture."

Appendix C

Financial Modeling Assumptions & Methodology

The financial results presented in the study were derived from a purpose-built spreadsheet financial model. The tool was used to examine the application of CCS to six CO_2 sources (including transportation and storage) from an investor's perspective: Fluid Catalytic Cracking Unit (FCC) operations at a petroleum refinery, hydrogen production, cement production, NGCC electricity generation, CHP, and ethanol production. This appendix provides an overview of the structure of the model, as well as key assumptions.

INTRODUCTION

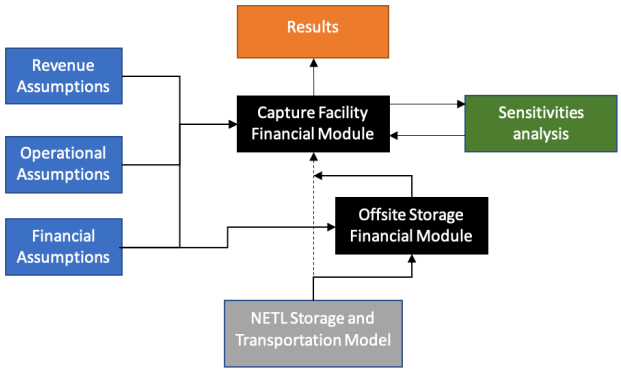
The overall structure of the financial model, which consists of eight sub-elements, is presented in Figure C-1. Revenue, operational and financial assumptions are sets of input parameters that align with the technoeconomic modeling presented in Chapter 3.

The core logic is contained within the Capture Facility and Offsite Storage modules, where inputs from the assumptions (and NETL Storage and Transportation Model) are used to generate project-specific internal rate of return (IRR), net present value (NPV) and annual cash flow outputs. The Capture Facility module examines the upstream (capture only) business and the Offsite Storage module examines the midstream/downstream (offsite transportation and storage) activities. The former considers capturing costs and incentives and compares across applications. The latter assumes a single transportation and storage operator offering gathering and storage services to one or more capture facilities, based on the assumptions found within the NETL study[1,2] and combines the volume and distances obtained from the findings in Chapter 3 for the Los Angeles and Bay Area hubs. The output from the Offsite Storage module is a breakeven rate for $/t$CO_2$ transported and stored that an investor would have to receive on average to achieve an NPV of zero (accounting for all equity, capital and debt repayments).

The Sensitivity Analysis module allows for one-and-two-dimensional exploration of IRR and NPV across project types. All output is displayed as part of the Results module.

FIGURE C-1

ELEMENTS OF THE FINANCIAL MODEL



GENERAL FINANCIAL MODEL STRUCTURE AND LIMITATIONS

The model is built with the assumption that the capture facility (with co-located storage, if such option is selected) is placed into a separate operating legal entity, referred to as the ProjectCo. The same is true for the Offsite Storage module; it is presumed a new legal entity is created with the pipelines and storage assets placed within it. It is acknowledged that this may not be the case in an actual deployment; companies may decide to treat the new investments as assets in similar fashion as acquiring any other kind of property, plant and equipment. However, the separate entity approach increases clarity of analysis for the purposes of this study, removes company-specific idiosyncratic distortionary effects and makes it easier to measure the incremental impact of the CCS investment.

The financial model treats the ProjectCo as wholly owned by cash equity investors; that is, details of tax equity structures, with different payouts for different classes of investors, are not considered. This simplicity facilitates the analysis and comparison of CCS investments across various applications. Moreover, it can be thought of as a starting point: if there is no return with such a "lean" structure, adding more complexity—potentially with additional frictions and costs—may not likely improve this baseline result.

The primary metric used to assess the returns in the model is the IRR. This choice was made considering its simplicity and robustness, in addition to its familiarity to investors and developers. The IRR metric provides the equivalent annual returns generated by the investment. The result is compared to investor hurdles rates, which are risk-adjusted targets for various kinds of investment types. The investment decision consists of selecting opportunities with the highest IRR, and at least above their desired hurdle rates for that given asset class. It is fairly common to see investors requiring IRRs above 10 percent for infrastructure or industrial projects.

Finally, both the Capture and Offsite modules utilize nominal values for all the financial statements; that is, all future costs and revenues are scaled considering a pre-determined inflation rate. This assumption is particularly relevant in this study, given the long-term nature of these investments.

CAPTURE FACILITY MODULE

Capital Expenditure, Plant Size, and Construction

The base case adopted in the financial model considers the average capturable volume of CO_2 in each application; that is, the total application emissions in California (i.e. total for cement, total for hydrogen, etc.), less the capture efficiency (85-90 percent of total emissions) and then divided by the number of existing plants. These values are given in column 2 and 3 of Table C-1. Capital costs (Capex) in columns 4 and 5 of Table C-1 are the same costs that were used to derive costs of capture on a per ton basis and used in the technoeconomics discussed in Chapter 3.

Further, every application incurs a Front-End Engineering Design (FEED) cost, which varies depending on application. The values considered in the financial model are estimates obtained from the interviews with experts and practitioners in the different industries and are given in column 6.

Finally the base case considers a three-year window to complete a FEED study and a subsequent two years for constructing the capture facility.

TABLE C-1

GENERAL AND CAPEX ASSUMPTIONS

Operational					
	General		*Capex*		
Industry	**Total emissions (Mt/year)**	**Average Plant Size (Mt/year)**	**PP&E ($ m)**	**PP&E ($/ton)**	**Cost FEED ($ m)**
Cement	7.80	0.880	$172.5	$195.95	$30.0
Ethanol	0.43	0.142	$10.8	$76.06	$0.5
H2	11.20	0.628	$148.0	$235.83	$5.0
NGCC	21.60	1.099	$391.6	$356.43	$10.0
CHP	10.10	0.605	$265.7	$439.20	$10.0
FCC	6.30	0.575	$156.7	$272.54	$20.0

Operating Expenditure

Three main elements compose the operating expenditure of a capturing facility: operations and maintenance (O&M), energy consumption (electricity and/or gas), and administrative expenses (SG&A). It is a widely adopted practice to estimate O&M costs as a percentage of the total Capex; this approach was used in the technoeconomic analysis presented in Chapter 3, and the same assumptions were used in the financial model (Table C-2).

Further, as for energy consumption, the model also uses the same underlying assumptions of unitary electricity consumption (in MWh/Mt) or unitary gas consumption (in MMBTU/Mt) used in Chapter 3 (depicted in Table C-2).

The administrative costs, typically including personnel, rents, management, information systems, legal fees are estimated as one percent of expected revenues.

TABLE C-2

OPEX ASSUMPTIONS

Operational			
	Opex		
Industry	Fixed (% Capex)	Power (MWh/Mt)	Gas Consumption (MMBTU/Mt)
Cement	7.0%	0.2	2.5
Ethanol	7.0%	0.1	–
H_2	7.0%	0.2	3.5
NGCC	5.0%	–	2.3
CHP	5.0%	–	2.3
FCC	4.4%	0.1	2.5

Revenue and Benefits

The module takes into consideration three possible sources of project cashflows: 45Q, LCFS credit sale, and Cap-and-Trade allowances sale.[a] All prices are set as dollar values as of January 2021 and the model considers the start of each cash-flow concomitant with the commercial online date (COD), set at Jan 2026. The eligibility for each one of these incentives will vary according to the application, as previously discussed in Chapter 3.

Further, the model also allows for only a portion of the total volume of CO_2 captured to be made eligible for incentives. Table C-3 outlines the baseline portion of captured CO_2 that each application would be eligible, for both Cap-and-trade and LCFS credits. The reasoning behind this can be found in Chapter 3.

TABLE C-3

PERCENTAGES OF ELIGIBILITY FOR EACH INCENTIVE

	Incentives	
Industry	Cap-and-trade (% of Captured CO_2)	LCFS (% of Captured CO_2)
Cement	100%	0%
Ethanol	0%	100%
H2	100%	80%
NGCC	100%	0%
CHP	100%	60%
FCC	100%	80%

Finally, there are some specifics regarding the 45Q and LCFS that are noteworthy. The 45Q is a tax benefit that can be used to reduce the amount of tax paid by the investors in other businesses they own, or even the ProjectCo if there is enough taxable income. As a tax benefit, the 45Q benefit itself is not taxable, and is not treated as cash. This means that it cannot be used to pay expenses and debt. The 45Q benefit is not added to the revenues produced by the project but instead considered as a benefit paid directly to the investors.

The current regulation requires that part of the LCFS credits generated by a CCS unit be deposited in a Buffer Account, that would be used in the case of leakage of the stored CO_2. As the value deposited in this buffer is not recovered by the project, at least not in the short-term, the financial model treats this compulsory deposit as a "haircut" in the total of credits generated. This value is assumed to be 10 percent.

a Note that the base case does not include cap-and-trade revenues; because CCS projects are not elibible for cap and trade, these calculations may only appear as a sensitivity within the study.

OFFSITE STORAGE MODULE

Capex and Opex

All Capex and Opex assumptions were obtained from the Storage NETL models for Storage[1] and Transportation[2], with the values adjusted for 2020 dollars. Table C-4 displays the assumptions used to obtain values from the NETL models (all parameters not mentioned here were kept at their standard values):

TABLE C-4

STORAGE AND TRANSPORTATION MODEL ASSUMPTIONS

Transportation Model	• Length of the Pipelines: 200 miles • Volume of CO_2 transported: 15Mt/year • Capacity Factor: 80%
Storage Model	• Volume of CO_2 stored: 15Mt/year per facility • Formation: Winters (in Sacramento, CA)

Revenue

The primary source of revenues considered for the central storage and pipeline infrastructure are contracts for transporting and sequestering the CO_2. It is conceivable that some of the tax benefits from the 45Q could be shared between the capturing facility and the hub operator, however for the sake of simplicity, only a contracted setting is modeled.

The model allows for two commercial contracts (Table C-5 illustrates the details of one contract) that can be concomitant or otherwise. The basic information necessary for each contract are the start date (initially set to the same date as the COD), term, volume (in the percentage of the total volume of CO_2 processed), and initial price (the price is adjusted by the same inflation rate).

TABLE C-5

TRANSPORTATION/STORAGE CONTRACT ASSUMPTIONS

Start Date	date	1-Jan-27
Term	years	30
End Date	date	1-Jan-57
Volume	%	100%
Initial Price	$/MT	22.00
As of	Date	1-Jan-24

FINANCIAL ASSUMPTIONS

Both Capture and Offsite Storage financial modules share similar financial assumptions. The following sections cover both modules, and specific comments are presented where necessary.

Debt

Focusing once more on simplicity, both modules use a straightforward capital structure: 50 percent equity and 50 percent debt for all pre-operation Capex investments. This means that all Capex investments executed before the commercial operation date are funded with equal amounts of cash from investors (equity) and lenders (debt). Pari passu is the standard option, where the lender provides cash in pace with the equity investor. Table C-6 illustrates the debt assumptions.

TABLE C-6

DEBT ASSUMPTIONS FOR BOTH FINANCIAL MODELS

Target Amount	%	50%
Bridge Disbursement date	date	pari passu
L/T Disbursement date	date	1-Jan-28
Amortization	years	10
Interest Rate	%	5.0%
Upfront fee - Bridge	%	1.5%
Upfront fee - Long term debt	%	1.0%
Grace Period	years	1.0
Target DSCR[b]	Multiple	1.45x

A second set of assumptions refer to the conditions of the loans, specifically, amortization period, interest rate, fees, and grace period. The amortization period and grace period define how much time the company will have to pay back the loan. Both financial modules use the constant amortization method, meaning that equal payments of the principal amount of the long-term loan will be paid over the amortization period—in the default case, equal installments over 10 years. The amortization period starts after the COD and the grace period. The latter, as the name suggests, is the time period given to the ProjectCo to stabilize its business before paying back the loan. The default grace period is one year.

Finally, the financial fees are provided as percentages of the total value of the loan, charged by the financial institution to structure the debt. It is a common practice in project finance to have two concatenated loans: a bridge loan, provided during the construction, and a long-term loan, provided just after the COD to pay the first loan, and carried by the ProjectCo during the defined duration. Two fees are then charged to structure those loans, with the default value of 1.5 percent and one percent of the total amount borrowed, respectively.

Financial Responsibility Trust Fund

The permits for UIC Class VI wells (the class required for permanent storage) require that developers demonstrate financial responsibility for post-injection activities such as emergency and remedial response, corrective action, well plugging and site closure. The total amount to be committed depends on several factors including the volume of CO_2 stored, plume size, leakage risks, potential adverse effects, etc.

The regulation allows the permitting authority to request a set of instruments from the developer as a guarantee of such financial responsibility, among them, trust fund, surety bonds, letter of credit and insurance. A trust fund structure was used to model this requirement, with underlying assumptions given in Table C-7.

TABLE C-7

FINANCIAL RESPONSIBILITY ASSUMPTIONS

Value	$/t	2.6
Pre-construction Payment	%	15%
Pre-injection Payment	%	45%
Interest rate	%/y	1%
Duration	years	50

The default unitary value ($ per ton of CO_2 stored) and pay-in period considered in both financial models were based on the UIC Class VI permit obtained by FutureGen Industrial Alliance[3] in the state of Illinois. That permit establishes three milestones: permit issuance, seven days before injection and within a year of permit issuance, and two years of permit issuance. Given the construction time may vary considerably among different applications and storage size, the financial model relaxes the time constraint of those milestones, considering three pay-in events as shown in Table C-8.

b Debt Service Coverage Ration – A measure of a firm's available cash flow to pay current debt obligations.

TABLE C-8

FINANCIAL RESPONSIBILITY PAY-IN MILESTONES

Installments	Milestone	Amount paid
Pre-construction Payment	End of FEED studies (permit is expected to be issued)	15%
Pre-injection Payment	Commercial operation date (injection is expected to begin)	45%
Post-injection Payment	One year of commercial operation	40%

The trust fund is also expected to generate returns – even though the investor does not manage it, the trustees will invest the money on their behalf. However, given the low rates of bonds (US10Y T-bond trading near 0.66 percent) and other fixed-income investments, the expected returns of the trust fund in the default case are set conservatively to one percent nominal, or below the expected inflation rate of two percent.

Usually, the trust-fund has to be held over the entire commercial operation of the storage facility and then it can be gradually reduced in the post-injection period, once the costs it guarantees are incurred. For example, after the well is plugged, the amounts for well plugging can be deducted from the fund. Again maintaining a conservative approach, both financial models consider the trust fund is kept with its full amount over 50 years in the base case.

Note that the financial responsibility bond appears on the balance sheet of the sequestering ProjectCo. In the case of co-located storage, it will appear on the balance sheet of the capturing ProjectCo (as this is considered a single entity). If however offsite storage is modeled/considered, then the financial responsibility bond is removed from the capturing ProjectCo balance sheet and placed on that of the transportation and storage ProjectCo. In this case, the cost of the bond is contained in the transportation/storage contract price.

Distributions and Exit Value

The final element of both financial models is essentially the cash-flow to the investors. In both modules, this comprises the net income and the available cash is distributed to the equity investors. The base case brings both numbers set to 100 percent, to estimate the maximum possible return to the investors.

Two other sources compose the return of the investors. The first is the 45Q tax benefit. Since this benefit is not cash (i.e., can't be used to pay expenses or debt) and not taxable, its proceeds are added directly to the outflows paid to the investors.

Finally, there is the residual value of the ProjectCo. After its lifetime, the ProjectCo may still have a residual in their books; for example, due to not fully depreciated assets, deferred taxes, or retained earnings. In such cases, the financial models consider the ProjectCo will be liquidated, and only a portion of the book value will be recovered. The standard value for this portion is 0.80x; that is, only 80 percent of the existing book value is recovered. The exception is the Trust Fund; which has to be held for several years, even after liquidation. A simplification is used in this case – when the liquidation occurs, the present value of the existing Trust Fund is considered among the cash-flows to the shareholders.

Endnotes

1 EPA Archives | US EPA. https://archive.epa.gov/region5/water/uic/futuregen/web/pdf/attachment-h.pdf

2 National Energy Technology Laboratory (2018). FE/NETL CO2 Transport Cost Model. U.S. Department of Energy. Last Update: Mai 2018 (Version 2b)

3 EPA Archives | US EPA. https://archive.epa.gov/region5/water/uic/futuregen/web/pdf/attachment-h.pdf

Appendix D

Expert Interview Methodology & Summary

In this study, expert elicitation employing a semi-structured interviewing method coupled with snowball (referral) and theoretical sampling approaches, was used as the basic methodology to gather practitioner perspectives on CCS in California. Expert elicitation refers to formal procedures for obtaining and combining expert judgments. Expert elicitations typically include multiple experts to capture diversity of knowledge, background, and opinion.[1] Speaking with multiple practitioners that span the CCS value chain—including project developers, financiers, investors, industry analysts and industry associations—was an important feature of the work, adding nuance, richness, perspectives and feedback afforded by stakeholder specific efforts in CCS. By collecting primary data from various stakeholder types across different organizations, this kind of interviewing attempted to mitigate the "single-firm blind spot"[2] by exploring and adopting a pluralistic view. Further, this qualitative data collection complemented the technoeconomic, policy, and financial analysis undertaken throughout the study, helping guide the breadth and depth of those efforts in an iterative fashion.

An initial set of interviewees was identified through existing study authors' connections and relationships via their collective professional networks. From this starting point, additional potential participants were identified through snowball sampling (referral sampling) and theoretical sampling. Referral sampling identifies potential additional experts through the connections and social/professional networks of the existing interviewee pool. For example, an interviewee from a refinery company would make an introduction on behalf of the study team to a counterpart at another refinery. Theoretical sampling is a process where the ongoing accumulation of data and evidence shapes where next to collect additional information, in order to develop a view (or theory) as it emerges. For example, as questions surrounding pipeline transportation became more prevalent through stakeholder discussions, seeking more information from expertise on pipeline permitting, ownership, rights of way, etc. led to additional interviewees being recruited by the study authors.

Semi-structured interviews were used to gain information from each of the interviewees/experts who were ultimately selected to participate. A semi-structured interview—used routinely in social science research—employs an open conversational format, allowing new ideas to be brought up during the interview as a result of what the interviewee says. The interviewer in a semi-structured interview generally has a framework of themes, questions and concepts to be explored.

Interviews—administered by a subset of the study authors—were conducted on the premise of "deep background," where direct quotes from interviewees would not be used, there would be no recordings other than typed/written notes taken by interviewers, and individual names or companies would not be disclosed in the final report. This kind of sourcing aligns with standard practice in human-subject research[3] increasing the level of comfort of the interviewee and leading to greater depth of conversation and ideas explored. All interviews were conducted out of the free will of the participants/interviewees, with no compensation indicated or offered. Interviewees were free to decline to answer any question (or parts of questions). For each interview, multiple interviewers from the research team were present, affording multiple lines of inquiry, interpretations of the conversation, and corresponding volume of notes. Notes

and additional interviewer perspectives were compiled into a central document for recordkeeping, synthesis and further internal (study authors only) discussion and debate.

Fifty-three (53) semi-structured interviews of 30-75 minutes in length were conducted as part of this study. All interviews occurred either via conference call (phone) or online platform (e.g. Zoom, Microsoft Teams, etc.).

Interviews occurred during the period April – September 2020 (~six months inclusive), comprising three stakeholder types across 12 industry domains. Table D-1 shows the number of different kind of stakeholders represented in the interviews. Note that these values are lower bounds on the number of individual interviewees, as some interviews had multiple participants/interviewees from a given stakeholder firm/organization.

TABLE D-1

SUMMARY OF STAKEHOLDERS INTERVIEWED FOR ANALYSIS[a]

	Interviewee/Stakeholder Type			
Industry	Analyst/Industry Association	Investor	Project Developer	**Total**
Cement	3			**3**
Chemicals			3	**3**
Diversified Energy	2		13	**15**
Environmental Advocacy	1			**1**
Infrastructure	3	3	2	**8**
Investment & Financial Services		3		**3**
Power			6	**6**
Private Equity		2		**2**
Public Sector	3			**3**
Refinery			5	**5**
Reinsurance	2			**2**
Utility			2	**2**
Total	**14**	**8**	**31**	**53**

a In addition to stakeholder interviews, the external project Advisory Board provided significant insight and input and includes representatives from environmentals NGOs, think tanks, labor unions, academia/research, and industry, as well as former government officials.

Endnotes

1 Colson, A., Cooke, R. (2018) Expert Elicitation: Using the Classical Model to Validate Experts' Judgments. *Review of Environmental Economics and Policy*, 12(1): 113-132.

2 Lumineau, F. & Oliveira, N. (2017) A Pluralistic Perspective to Overcome Major Blind Spots in Research on Interorganizational Relationships. *Academy of Management Annals*. 12(1); 440-465.

3 Stanford Research Compliance Office https://researchcompliance.stanford.edu/panels/hs

Errata

REVISION 1, OCTOBER 25, 2020

- Page S-4: "412,000 jobs in oil and gas" changed to "412,000 traditional energy jobs"
- Page S-12: "biennial integrated resource plan and long-term procurement planning process" changed to "integrated resource plan (IRP)"
- Page 14, Figure 1-11: updated to revised figure
- Page 20, Figure 1-14: updated to revised figure
- Page 34, Box 2-1: "Captured CO_2 is sold to offtaker for injection into a non-co-located (offsite) depleted well for EOR purposes, and subsequently stored" changed to "captured CO_2 is sold to offtaker and transported via pipeline for non-co-located storage via CO_2-EOR"
- Page 34, Box 2-1: "Captured CO_2 is injected into depleted well for EOR, and subsequently stored" changed to "captured CO_2 is injected for CO_2-EOR"
- Page 51, Figure 3-6: updated to include revised storage capacity numbers
- Page 51, "4.2 GW" changed to "four GW"
- Page 51, "Two GW" changed to "four GW" (now on p. 52 in Revision 1)
- Page 86: "California's biennial IRP-LTPP process. The IRP-LTPP… The IRP-LTPP process" changed to "IRP process… The IRP… The IRP process"
- Page 111: "Issue Guidance on CCS Eligibility Under SB100, IRP-LTPP, and IEPR" changed to "Issue Guidance on CCS Eligibility Under SB100, IRP, and IEPR"
- Page 111: "California's biennial IRP-LTPP process" changed to "California's IRP process"
- Page 111: "Planning for these goals occurs through the IRP-LTPP process" changed to "Planning for these goals occurs through the IRP process"
- Page 111: "…the IRP-LTPP as well as…" changed to "…the IRP as well as…"
- Page 116: "Support Early Project States with Grants" changed to "Support Early Projects with State Grants"
- Page B-2: Deleted "The analysis assumes a relatively flexible load growth evident by the moderate increase in peak demand."
- Page B-2, Table B-3: "(60 GW peak)" changed to "(65 GW peak)"
- Page B-3, Figure B-2: updated to revised figure
- Page B-3, Figure B-3: updated to revised figure
- Page B-3, added "California's annual system costs are inclusive of annualized capital costs of building new generation and storage resources, annual O&M costs, annual fuel costs, annual net import/export costs, and annualized spur line costs for new generation resources. Annual net import/export costs are calculated using the marginal cost of generation and import/export amount at the time of California's exchange with NW and SW regions. Spur line costs are assumed to be $3,670/MW-mi (2013 USD, $3,960/MW-mile in 2018 USD) in WECC, and x2.25 that cost in California. We further assume an average spur line distance of 12 miles and annualize the capital costs using a capital recovery factor of 7%. Spur line costs are added for new geothermal, wind, and solar capacities. A reliability multiplier of 1.6 is considered for new geothermal capacities based on assumed need for double-circuit lines. Spur line costs for new CCS capacities are not considered due to existing spur lines at the site of retrofit. Note the annual system cost does not include distribution or transmission system developments needed and associated costs in 2030."
- Page B-3: Deleted "Additional Results" Heading
- Page B-4: Deleted "Additional sensitivities with higher and lower battery storage costs, lower PV and wind costs, higher retrofit costs, and lower gas costs were run for this analysis as well. Table B-4 summarizes the additional assumptions made in the sensitivity cases. Across all the sensitivity cases, system costs for scenarios with NGCC-CCS are consistently lower than scenarios without NGCC-CCS. Furthermore, the cost-optimal level of CCS was consistent around 4.2 GW across all sensitivities."
- Page B-4, Table B-4: deleted table
- Page B-5, Figure B-4: deleted figure

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- Page S-7: "By 2045, one study, estimates that California will need approximately 30 GW of clean firm resource to ensure sufficient supply all year long. That study also found that a 2030 scenario with NGCC-CCS saved $750 million per year in total electricity system costs compared to a system without CCS that relied heavily on renewables and battery storage.21 changed to "This analysis found that a 2030 scenario with NGCC-CCS saved $750 million per year in total electricity system costs compared to a system without CCS that relied heavily on renewables and battery storage. A separate study estimates that by 2045, California will need approximately 30 GW of clean firm resources to ensure sufficient supply all year long.[21]
- S-7: "DAC relies on carbon storage or utilization to after it is captured" changed to "DAC relies on carbon storage or utilization after it is captured"
- S-15: "Create transport and storage operator." changed to "Create CO_2 transport and storage operator."
- 8: "leading to loss of life, destroying property, and releasing significant GHG emissions" changed to "leading to loss of life, the destruction of property, and the release of significant GHG emissions"
- 31: "concludes, however that," changed to "concludes, however, that"
- 44: "60MtCO_2e" changed to "60MtCO_2"
- 48: "natural-gas generating" changed to "natural gas generating"
- 48: "reliability, at the same time" changed to "reliability; at the same time,"
- 49: "it will critical" changed to "it will be critical"
- 61: On Table 3-3-, in the 59 MtCO_2/yr column, for the San Francisco Bay Area hub row, the number of CHPs changed from 5 to 6; for the Los Angeles hub row, the number of CHPs changed from 4 to 3; for the co-located row, the number of CHPs changed from 6 to 5
- 82: "questions remain however" changed to "questions remain, however"
- 82: "LCFS, achieve key policy goals." changed to "LCFS, achieves key policy goals."
- 85: "emitter captures and stored" changed to "emitter captures and stores"
- 86: "Combined emissions from these sources is 11" changed to "Combined emissions from these sources are 11"
- 92: "oil -and gas industry." changed to "oil and gas industry."
- 109: "exploring options to appoint" changed to "explore options to appoint"
- 110: "million which are the" changed to "million which are under the"
- 111: "which set at 50 percent" changed to "which set a 50 percent"
- 117: "through at least 2045, would" changed to "through at least 2045 would"
- 123: "H2" changed to "Hydrogen"
- A-1: "they may fall underneath." changed to "to which they may be subject."
- A-1: "As is pertains" changed to "As they pertain"
- A-1: "expectations between the" changed to "expectations among the"
- A-3: caption "a CCS projects" changed to "a CCS project"
- A-8: "At present, regulated by EPA Region 8.73 Primacy pending; when finalized, minimum monitoring period is 10 years" changed to "Primacy: Post-injection site care shall be for a period of not less than ten (10) years"
- C-3: Table C-3 title, "Percentages of Eligibility to Each Incentive" changed to "Percentages of Eligibility for Each Incentive"
- C-5: "storage) requires" changed to "storage) require"
- C-6: "is set conservatively" changed to "are set conservatively"
- D-2: "Interviews occurs" changed to "Interviews occurred"