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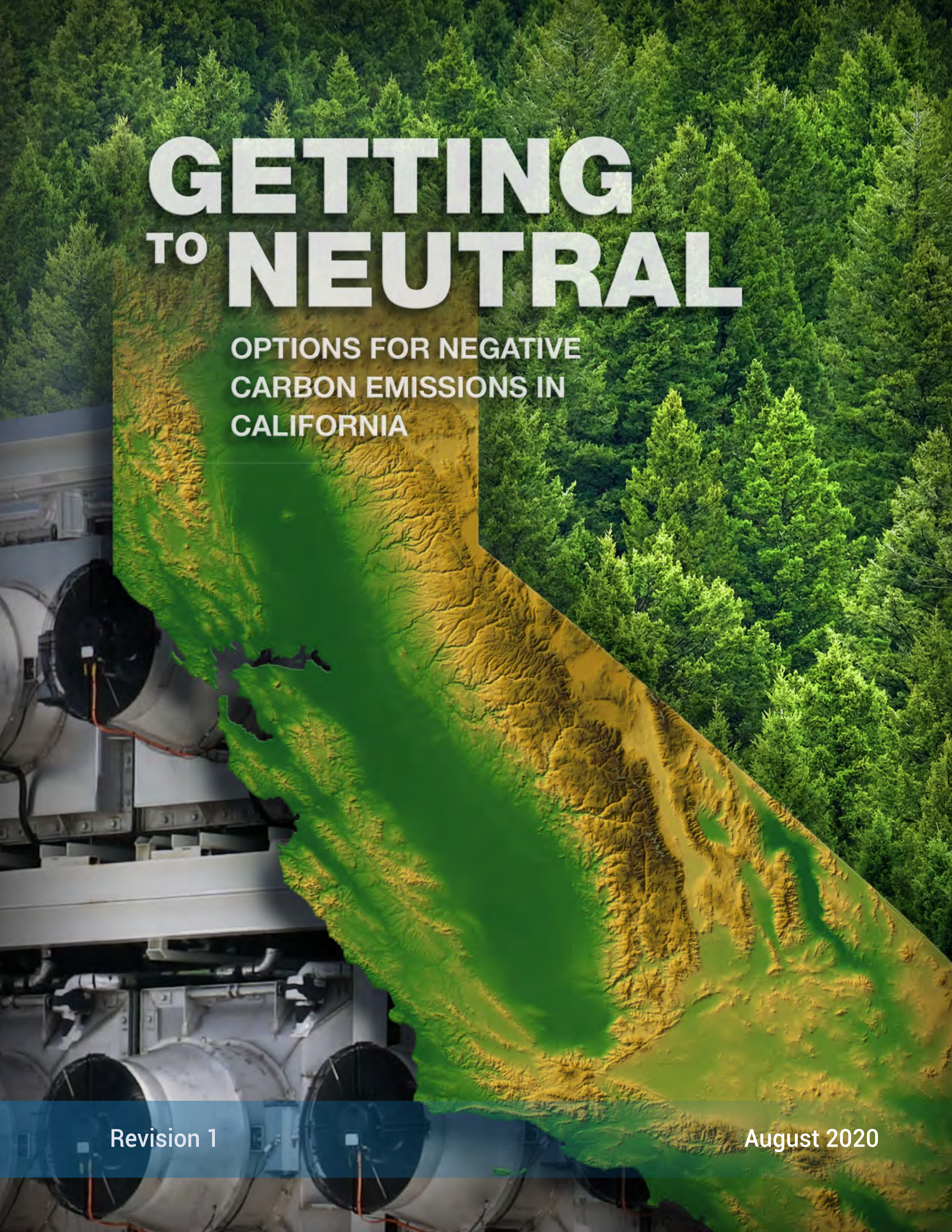

GETTING TO NEUTRAL

OPTIONS FOR NEGATIVE CARBON EMISSIONS IN CALIFORNIA

Revision 1

August 2020

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LLNL-TR-796100

Getting to Neutral
Options for Negative Carbon Emissions in California

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An accessible version of the entire report is available at:

https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf

Editorial Note:

Only minor editorial corrections have been made in this revision of the original report that was published in January 2020. No numerical content or assumptions have been changed or added.

Preface

This report is an assessment of negative emissions pathways—ones that physically remove CO_2 from the atmosphere—that can help California achieve carbon neutrality by 2045, or sooner. It integrates original research findings with current published research on three main pillars of negative emissions: natural and working lands, carbon capture from biomass conversion to fuels, and direct air capture.

The focus and scope of this report is unique: it only addresses practices and technologies for removing carbon dioxide from the air. It also encompasses the entire breadth of strategies, from land management to the latest technological options, and it evaluates the cost of every step of the solution, from waste biomass collection to carbon dioxide transport and geologic storage. The methods are intended to be transparent; details of the calculations and underlying data are included in the report body and appendices.

This study intentionally avoids any discussion of policies and does not include current incentives; it provides a range of options, tradeoffs and costs that can be used to inform future policies. The key finding of this report is that carbon neutrality is achievable.

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EXECUTIVE SUMMARY

California can achieve its goal of carbon neutrality by 2045 through negative emissions

To reach its ambitious goal of economy-wide carbon-neutrality by 2045, California will likely have to remove on the order of 125 million tons per year of CO_2 from the atmosphere. California can achieve this level of **negative emissions** at modest cost, using resources and jobs within the State, and with technology that is already demonstrated or mature. This is our conclusion after a comprehensive, first-of-its-kind, quantitative analysis of natural carbon removal strategies, negative emissions technologies, and biomass and geologic resources in the State, using methods that are transparently detailed in this report. We also find that realizing this goal will require concerted efforts to implement underground carbon storage at scale, build new CO_2 pipelines, expand collection and processing of waste biomass, and accelerate learning on important technologies, like direct air capture.

Background

California has established itself as a worldwide climate leader through several landmark climate policies and targets, and has made considerable progress in top-priority emission reductions: using energy more efficiently, reducing the

BENEFITS OF NEGATIVE EMISSIONS

Negative emissions strategies add to other critical means of climate change mitigation. They hold important co-benefits for California:

- Air quality improvements, by replacing fossil transportation fuels and reducing biomass combustion and wildfires.
- Water quality improvements, by enhancing and restoring natural ecosystems.
- Protection of life and property, by reducing wildfires.
- Economic development opportunities for the Central Valley and other areas in need.
- Keep California on the leading edge of technological innovation that will have global impact.

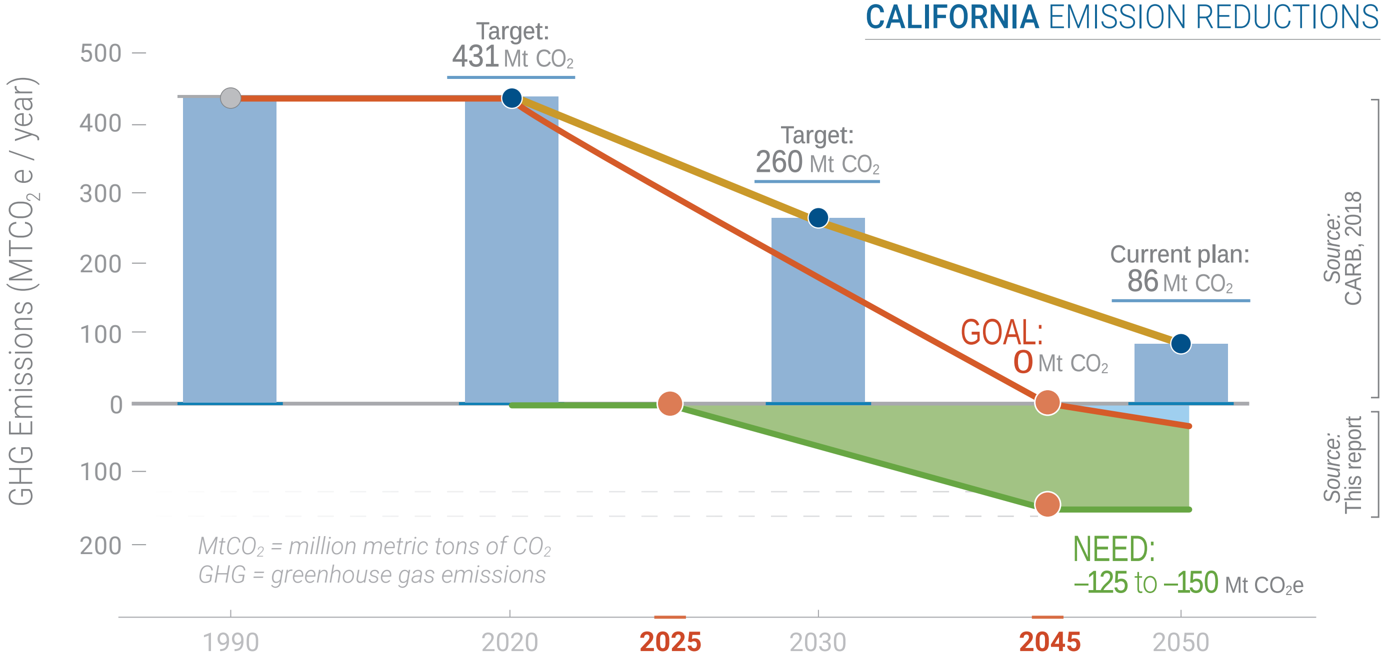


Figure ES-1. *Goals of California's emissions plan extrapolated to 2045 (CARB, 2017) with negative emissions estimates from this report.*

*California can add to its growing legacy of **pioneering practices, technologies,** and **policies** that are required worldwide in order to **meet the global climate challenge.***

Three pillars to reach
125 *million tons of negative emissions*

25 Mton/ yr

*Capture & store carbon through **natural and working lands***

84 Mton/ yr

*Convert **waste biomass** to fuels and store CO_2*

16 Mton/ yr

*Implement **direct air capture** and CO_2 storage*

KEY FINDINGS

By redoubling efforts to reduce and avoid existing emissions, and proactively pursuing negative emission pathways, **California can achieve its ambitious carbon-neutral goal by 2045.**

By increasing the uptake of carbon in its natural and working lands, converting waste biomass into fuels, and removing CO_2 directly from the atmosphere with purpose-built machines, **California can remove on the order of 125 million metric tons of CO_2 per year** from the atmosphere by 2045, and achieve economy-wide net-zero emissions.

California can achieve this amount of negative without buying offsets from outside the State. This approach addresses local emissions without the risk of leakage or offshoring, so the overwhelming majority of the **money is spent on local jobs and local industry.**

These negative emissions pathways come with important co-benefits to air and water quality, resilience to a changing climate, and **protection of life and property.**

California can achieve this goal at a **cost of less than $10 billion per year,** less than 0.4% of the State's current gross domestic product.

Some of the removed carbon will be bound in natural systems or soils, but the bulk will need to be **permanently** and **safely stored deep underground.**

Only moderately and highly mature technologies are required to achieve this negative emissions potential; however, accelerating demonstration and deployment for some of them is a key need.

To realize these benefits, **concerted efforts are required to broaden uptake of new land management practices, establish infrastructure, including waste biomass processing plants,** to produce carbon-negative fuels **and pipelines to transport CO_2** to underground permanent storage sites.

The importance of achieving this level of negative emissions stretches far beyond California – the Golden State can demonstrate to the world that carbon neutrality is achievable.

carbon footprint of its electricity supply, putting cleaner cars on the road, reducing emissions from transportation fuels, and more.

Despite this progress, substantial challenges remain in rapidly decarbonizing the transportation, agriculture, and industrial sectors, and delays are possible. Certain greenhouse gas emissions (such as methane and nitrous oxide) are difficult to eliminate. Some fossil fuel uses, such as in aviation, cannot yet be eliminated in a straightforward way.

The goal of being entirely carbon neutral by 2045 is substantially more ambitious than the State's previous long-term goal of achieving an 80% reduction from 1990 emission levels by 2050. In addition to further intensifying decarbonization efforts in the areas that the State has already championed, the new goal requires ingenuity and innovation that goes beyond today's success stories.

California can attain this new goal if it now also invests in solutions that directly remove carbon dioxide from the atmosphere. The function of these negative emissions is to neutralize any residual emissions and provide a new cushion of security over and above current efforts. We estimate that the State should aim to remove on the order of 125 million metric tons of carbon dioxide (Mt CO_2) annually from the atmosphere by 2045, as shown in Figure ES-1 on page 1.

Negative Emissions:
A Logical Next Step for California

We analyzed how California can use resources and technology to achieve our goal of 125 million tons of negative emissions per year. We define negative emissions as CO_2 that is physically removed from the atmosphere, such as through biomass growth or direct air capture. It does not include reductions in current or projected emissions. We drew from existing literature, standard tools, and our own expertise to assess the feasibility and cost of more than 50 negative emissions pathways. We selected the lowest cost and most productive pathways to create a negative emissions strategy that has three pillars (Figure ES-2):

1. Capture and store as much carbon as possible through better management of natural and working lands
2. Convert waste biomass to fuels and store the CO_2
3. Remove CO_2 directly from the air using purpose-built machines and store the CO_2

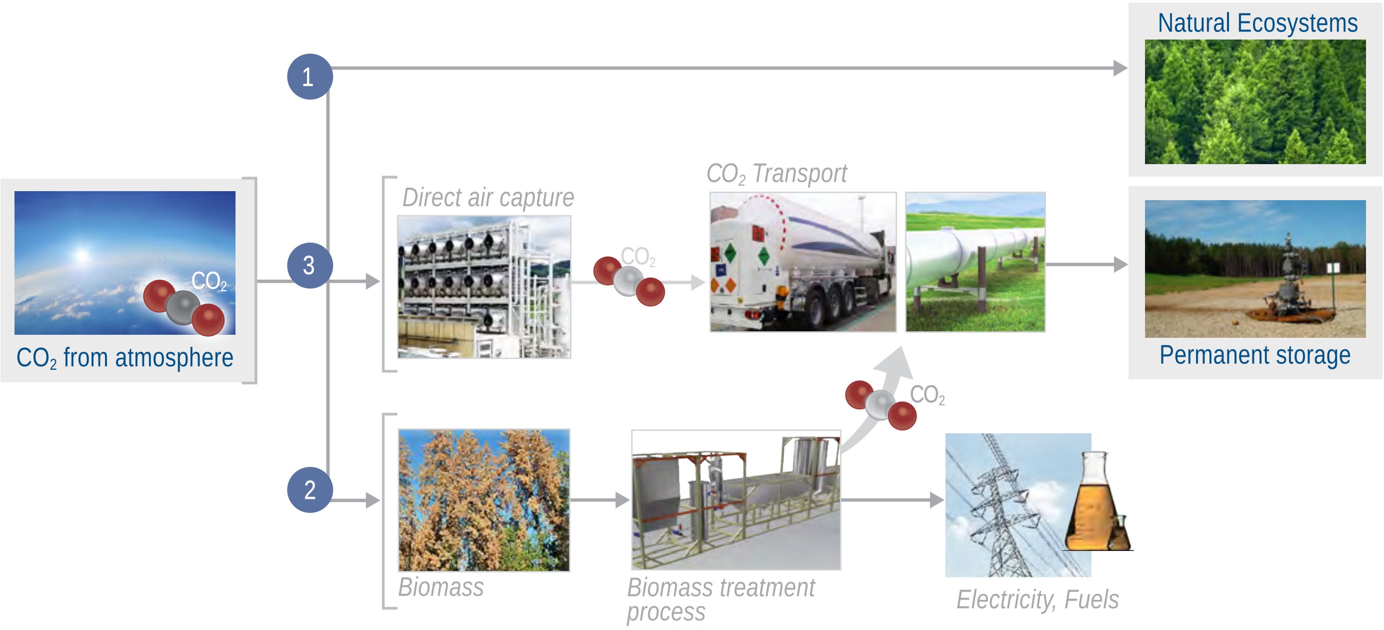


Figure ES-2. *The three main pathways to negative emissions (removing CO_2 from the atmosphere) for California are restoring natural ecosystems, converting waste biomass to fuels while capturing the CO_2 generating during processing, and direct air capture machines.*

1st Carbon-Reduction Pillar:
Natural Solutions

Using the Power of Nature to Remove CO_2 from the Atmosphere

Natural solutions encompass activities such as changes to forest management to increase forest health and carbon uptake, restoration of woodlands, grasslands and wetlands, and other practices that increase the amount of carbon stored in trees and soils. These approaches are among the least expensive we examined, averaging $11 per ton of CO_2 removed from the atmosphere. In addition, they have important co-benefits to air and water quality, ecosystem and soil health, resilience to a changing climate, and protection of life and property through fire risk reduction. Unfortunately they are limited by land and ecosystem availability. Details on land treatment measures, costs, and uncertainty can be found in **Chapter 2.**

2nd Carbon-Reduction Pillar:
Waste Biomass

Convert Waste Biomass to Fuels and Store CO_2

Waste biomass is widely available across California, with about 56 million bone dry tons per year available from trash, agricultural waste, sewage and manure, logging, and fire prevention activities (Figure ES-3). Today, this biomass returns its carbon to the atmosphere when it decays or burns in prescribed fires or wildfires, or is used to produce energy at a power plant that vents its carbon emissions. Details on the waste biomass sources and quantities we used in our analysis, and associated constraints, collection costs, and current uses, can be found in **Chapter 3**.

Converting this biomass into fuels with simultaneous capture of the process CO_2 emissions holds the greatest potential for negative emissions in the State. A broad array of processing

All of California can participate in gathering the biomass needed for negative emissions

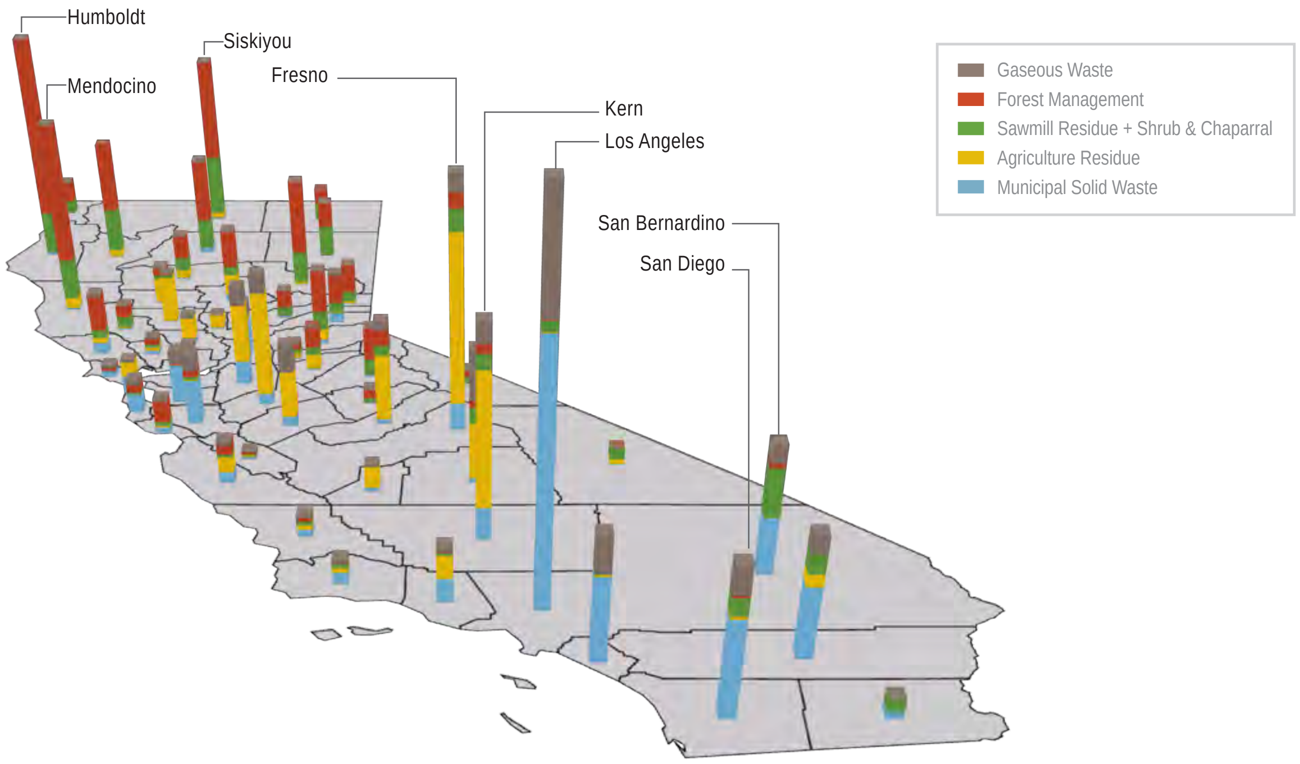


Figure ES-3. All of California can participate in collecting the biomass needed for negative emissions. *Our study assumed contributions across counties and resource types. In sum, 56 million bone-dry tons of waste biomass will be available in 2045, at a typical carbon content of 50%. Gaseous waste comes from landfills and anaerobic digesters. Forest management refers to residue produced from forest management treatments like mechanical thinning for fire control. Sawmill residue refers to the residue produced at the sawmill facilities. Shrub & chaparral refers to mostly shrubby evergreen plants located in semi-arid desert region of California. Agriculture residue includes orchard & vineyard residues, field residues, row residues, row culls, almond hulls, almond shells, walnut shells, rice hulls and cotton gin trash. Municipal solid waste includes paper, carboard, green waste and other organics.*

options is available, and includes collecting biogas from landfills, dairies, and wastewater treatment plants for upgrading to pipeline renewable natural gas; conversion of woody biomass to liquid fuels and biochar through pyrolysis; and conversion of woody biomass to gaseous fuels through gasification. Gasifying biomass to make hydrogen fuel and CO_2 has the largest promise for CO_2 removal at the lowest cost and aligns with the State's goals on renewable hydrogen. We link biomass processing technologies to each source of biomass and compare these processing technologies in terms of the amount and cost of CO_2 that can be derived from a given biomass source in **Chapter 4**.

3rd Carbon-Reduction Pillar:
Direct Air Capture

Machines to Remove CO_2 from the Air and Permanently Store it Underground

Direct air capture is more expensive than most negative emissions options for California, but has a nearly unlimited technical capacity, provided its energy needs (primarily heat) can be met from a low-carbon source. This option will inevitably have to be used to some extent, depending on the degree of adoption of other, less expensive options. Captured CO_2 must be directed to permanent storage. We envision facilities located near the highly suitable permanent geologic storage sites in California's Central Valley, as well as a smaller set that utilize geothermal heat where it is available in the Salton Sea region. Because land use for renewables would be very large for the amount of power needed for this amount of direct air capture (roughly 250 MW per million tons per year), natural gas power (with gas sourced nearby in California fields) at the direct air capture plant is the second best option after geothermal heat. Almost all the CO_2 from combustion would be captured and stored, resulting in a net reduction in atmospheric CO_2. Direct air capture technology options and associated costs are described in **Chapter 5**; Direct air capture and other technologies that have not been deployed at scale will get less expensive as more units are deployed. We describe how these costs decrease with technology learning in **Chapter 8**.

Where Will the Carbon Go?
Back into the Ground

Beyond carbon stored in plants and soils through natural solutions, putting the captured carbon away involves storing it permanently and safely thousands of feet underground as CO_2, in porous rock of the same kind that makes up California's oil and gas fields. The presence of oil and gas in these fields is, in fact, a clear demonstration of nature's ability to trap fluids underground over millions of years. California's deep sedimentary rock formations in the Central Valley represent world-class CO_2 storage sites that would meet the highest standards, with storage capacities of at least 17 billion tons of CO_2 according to our estimates – many decades' worth of capacity to store carbon from negative emissions pathways at the scale contemplated here.

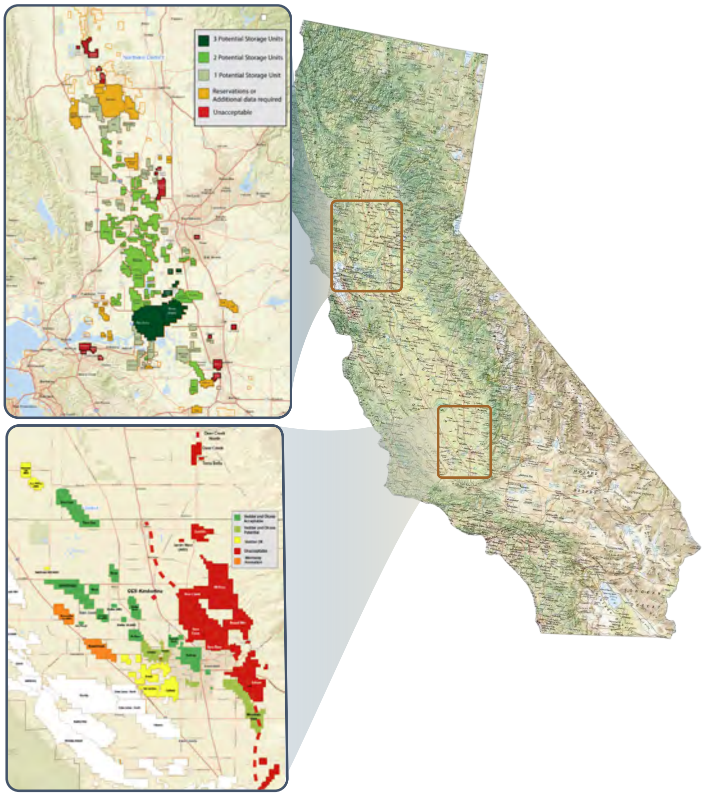


Figure ES-4. Two prospective areas for underground geologic storage. *Oil and gas fields are highlighted. Color indicates the degree of conformance with existing State and Federal standards for geologic CO_2 storage, as well as additional safety constraints. White fields have not been evaluated.*

Until now, the locations and storage capacities of suitable, permanent storage sites within the State have been based on high-level, low-resolution, basin-scale assessments. We advance this understanding to location-specific knowledge by assessing the storage capacity associated with California's oil and gas fields, as well as deep saline aquifers that share the same geology, for two extremely well studied areas with publicly available data: Kern County and the Sacramento-San Joaquin Delta (Figure ES-4). Both these regions have been sites of extensive oil and/or gas production, which results in the availability of geologic data. We used these data to evaluate CO_2 storage capacity, storage security, and the ability to comply with the strict regulations and standards that govern current underground CO_2 storage.

We conclude that these areas contain ample safe and effective storage sites. At depths below 3,000 feet, CO_2 converts to a liquid-like form that has about the same density and viscosity as oil. The fact that the geologic barriers in these regions have held oil and gas and other fluids underground for millions of years means that they are well-suited to secure storage of CO_2. Site-specific factors such as faulting and man-made penetrations will need to be evaluated carefully for each site storage operation, but our review of about 50% of the likely good storage zones in the Central Valley indicates that at a minimum 17 billion tons can be stored there, with the upper limit being 200 billion tons. 17 billion tons would provide more than 100 years of capacity at the rate that we anticipate California will require negative emissions. These findings are detailed in **Chapter 6**.

Transporting the Carbon to Its Burial Grounds

Transportation is a critical aspect of the negative emissions system. Our analysis shows that forest biomass resources are concentrated in the northwestern region of the state; agricultural residue resources in the Central Valley, and municipal solid waste and gaseous waste resources in the populated areas of the southern region. Promising CO_2 storage locations are mainly in the Central Valley. The transport problem is: What is the best way to move carbon from the biomass source regions to the storage sites?

There are multiple options for the mode of transport (truck, rail, pipeline) and the form of carbon to be transported. CO_2 by pipeline is the lowest cost option for large volumes. In **Chapter 7,** we assess various configurations of truck, rail, and pipeline transport as well as options for siting processing facilities. Many strategies yield reasonable costs, but a shared CO_2 trunk pipeline and use of existing rail lines are key to keeping costs low. For this study, a model was used to choose the lowest-cost transport mode for each county and carbon source type for several technology scenarios. The system-wide average transport cost is $10—18 per ton of CO_2 removed, depending on the technology scenario.

Necessary Systems and Infrastructure

The advantage of natural solutions is that they can be implemented with little infrastructure; however, their success depends on securing funds to implement them. Success also depends on the broad dissemination of practices across a large land area with potentially numerous owners and managers who must adopt the required practices.

Collecting California's full amount of waste biomass will require a concerted effort from farmers, landowners, waste handlers, and state agencies. In most cases, the biomass in our accounting did not have other current uses or economic value, such as that which would have been pile burned or landfilled. In other cases, we assume a change in biomass use to achieve negative emissions. If certain biomass types or sectors are not available for negative emissions, this only means that system costs will increase, and not that negative emissions cannot be achieved. We present cost sensitivity to potential biomass availability constraints in **Chapter 9**. Additionally, the lowest cost pathway to negative emissions requires building the capacity to handle California's full amount of waste biomass, requiring the construction of a fleet of gasification, pyrolysis, and biogas upgrading/purification plants, which we estimate to be on the order of 50 to 100 facilities, the largest of which would be located in the Central Valley. These state-of-the-art, low-emissions facilities will reduce air pollution from existing burning of biomass, and also displace polluting fuels from the road.

Transport and geologic storage of CO_2 are essential to achieve the required negative emissions. While these steps are comparatively inexpensive, together requiring $10—20 per ton, they may be the most time-constrained aspect. While construction of CO_2 pipelines from biomass processing facilities to geologic storage is the lowest cost transport option, numerous logistical and regulatory hurdles may impede pipeline construction. Additionally, secure storage sites where the CO_2 can be stored permanently have to be characterized and selected carefully according to rigorous State and Federal geologic criteria, and require the consent of several land and mineral owners. Although sites like this can readily be found in California's Central Valley, it is not realistic to expect them to be situated immediately next to the CO_2 source as a rule, and the best geology may not coincide with the quickest legal and permitting lines of sight.

The Cost of Removing Carbon

Our analysis shows that by increasing the uptake of carbon in natural and working lands, converting waste biomass into fuels, removing carbon dioxide directly from the atmosphere with purpose-built machines, and safely and permanently storing captured CO_2, California can remove 125 million metric tons of CO_2 per year from the atmosphere by 2045, and achieve net-zero statewide emissions. The lowest-cost set of strategies to do this, according to our assessment, is one which prioritizes gasification of biomass to hydrogen. This scenario is shown in Figure ES-5, where negative emissions pathways are ordered from least to most expensive. The width of the bar represents the quantity of CO_2 removed at full deployment. The costs shown include biomass collection, plant capital and operating expenses, transport, CO_2 storage, and revenue from sale of coproducts at market rates. The quantity of conventional direct air capture is chosen so that the sum of all pathways removes 125 million tons annually, although direct air capture can remove much more if needed.

The total cost of the scenario with the lowest-cost set of technologies is $8 billion per year, or $65 per ton CO_2, which is quite modest compared to California's current gross domestic product (0.34%) and compared to previous estimates of the cost of negative emissions. We also investigate other scenarios with different technology choices, product selling prices, direct air capture costs, and biomass availability and find that the total system cost lies in the range of $5—15 billion for most reasonable sets of assumptions. Higher system costs are possible, but can be avoided by investors and policymakers who actively work to minimize costs.

These scenarios are achievable with biomass conversion and air capture technologies that are either already deployed today, or ready to be piloted at scale. The speed at which the State deploys new technologies will directly impact the cost and practical realization of negative carbon emissions. Therefore, a critical part of making these estimates a reality is initiating at-scale and near-scale technology pilots as soon as possible.

ACTIONS

Scale up and **accelerate** implementation of natural solutions.

Ensure eligibility and economic viability of **negative emission pathways** under the **State's climate programs.**

Facilitate **collection** and **distribution** of a reliable waste biomass supply.

Ensure a viable permitting and siting framework for needed infrastructure, such as **biomass conversion, CO_2 transport and safe, permanent CO_2 storage.**

Buy down the cost of critical technologies such as **direct air capture** by accelerating learning.

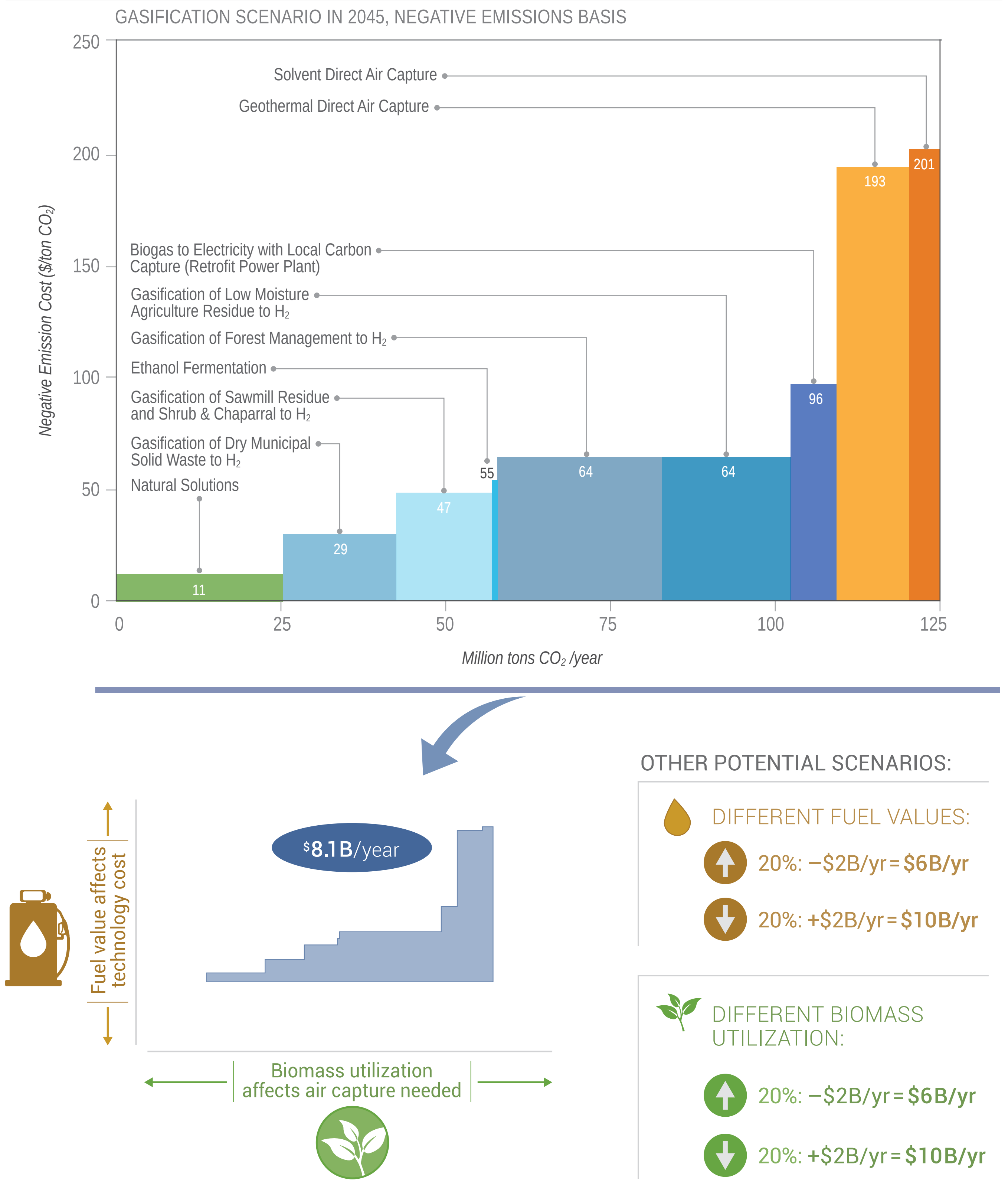


Figure ES-5. Cost of the negative emissions system. *(top) Average costs and cumulative quantities for the lowest-cost set of negative emissions pathways for California. All collection, transport, processing, and final storage costs for CO_2 are included, assuming full use of projected waste biomass resources in 2045. (bottom left) Total cost for the system is the area under the curve, which is $8.1 billion in the case shown. Fuel value affects the cost of biomass conversion technologies (height of the bars), while biomass availability affects the quantities of CO_2 removed by conversion technologies (width of the bars). (bottom right) Changing the fuel selling price or biomass availability by 20% changes the total system cost as shown.*

California can Reach its 2045 Vision *and Lead the World in the Process*

Achieving 125 million metric tons of CO_2 per year of negative emissions for California will require that natural and working lands are managed in different ways. Biomass processing infrastructure will need to be planned, financed, and built around the state to produce carbon-negative fuels. Machines that remove CO_2 directly from the air will need to be built and powered. Geologists will need to identify the best sites to store CO_2 deep underground permanently and securely, and land and CO_2 will need to be transported and stored across many land and mineral ownership boundaries. Most of these steps come with potentially complex and time-consuming permitting processes.

But our analysis shows that most negative emissions options make, or are close to making, economic sense today. Figure ES-5 shows the progression of options, from inexpensive to most expensive. The total system cost depends strongly on the degree to which biomass is used. It also depends on the value of the fuels made from biomass – the more valuable they are, the less the resulting CO_2 costs. California's final plan will certainly be a mix of many technologies and approaches, but our work indicates that the overall cost is not a strong function of the actual technologies, and many approaches can be embraced.

The opportunity to act is unique. Pursuing negative emissions now enhances the security of California's own emissions outcome. The State is no stranger to innovation, and can pioneer climate solutions, technologies and policies that will undoubtedly need to spread globally to deal with the global climate crisis. California is ideally situated to lead in this task, with a long history of aggressive policies for efficiency, renewable energy and carbon reduction, along with geology and a workforce ideally suited to this task.

The stage is set. The actions needed today to help California be carbon neutral, and ultimately carbon negative, are available and affordable. And this plan does not need to wait for 2045. Progress can begin immediately, and the carbon reductions we envision can be achieved much sooner, accelerating a truly carbon-neutral economy for California, with a carbon negative economy in sight.

CHAPTER 1

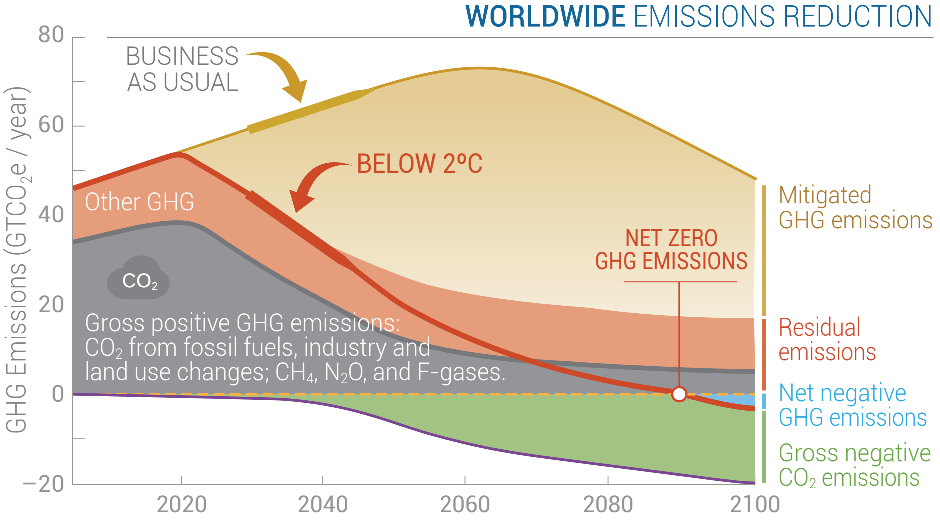
Introduction

Detailed studies tell us that the energy technologies the world is currently focused on—renewables and electrification—will not be enough for a viable planet. We need to actively decarbonize the atmosphere to a safe level [1], [2], [3], [4]. Figure 1 shows two possible trajectories for emissions of greenhouse gases. In yellow is the carbon emissions trajectory for emissions if we continue current activities with no changes. It will have devastating results for temperature and climate.

If we follow the red trajectory of worldwide carbon emissions, we have about a 66% chance of staying below 2°C of global total temperature increase [4]. Achieving 1.5°C would be much more difficult. Through Governor Brown's executive order B-55-18, California set a goal of achieving net carbon neutrality as soon as possible, and no later than 2045. This goal shares the same energy mechanics as the global ambitions described by the Intergovernmental Panel on Climate Change (IPCC) and shown in Figure 1, and both are limited by the range of currently available tools [1]. Renewables, electrification of transportation, and the elimination of almost all fossil fuels, will only give us the worldwide reduction shown in brown. The cause of the problem is twofold: because we have been too slow to reduce heat-trapping gas emissions, and because it is very difficult to eliminate many of the greenhouse gases (such as methane and nitrous oxide) from our emissions. However, it is also partially due to the difficulty in removing some CO_2 from the economy; for example, the CO_2

Report Scope

- California needs negative emissions, removal of CO_2 from the atmosphere, to achieve its goal of carbon neutrality by 2045.
- We evaluate negative emissions technologies that either rely on plants to remove and store this CO_2 as biomass, or machines to remove and concentrate CO_2 for underground storage.
- This report evaluates the costs of the full suite of practices and technologies that must be brought together, including land management, waste biomass conversion, direct air capture, biomass and CO_2 transport, and geologic CO_2 storage.



Source: Jérôme Hilaire, Mercator Institute

Figure 1. *The green wedge represents the global amount of negative emissions—removal of CO_2 from the atmosphere—required to offset residual emissions and keep worldwide greenhouse gas emissions below that required to meet a 2°C future.*
Adapted from Fuss et al., 2018.

GHG = greenhouse gas,
CH_4 = methane, N_2O = nitrous oxide
F = fluorinated gases,
$GTCO_2e$ = giga (billion) tons of CO_2 equivalent

NEGATIVE EMISSIONS

Throughout this report, **negative emissions** is defined as the physical removal of carbon from the atmosphere. This removal must be long-term; the carbon must remain away from the atmosphere long enough to be consistent with climate stabilization. This is not defined within a specific number of years, but the negative emission pathways we consider are based on the assumption of essentially permanent removal. We do not consider conversion to short-lived products, for example, where the carbon is released after a few years or decades.

It is important to distinguish negative emissions from avoided emissions. The term **avoided emission** in this report refers to an emission that would have taken place, but is prevented due to the implementation of a negative emissions pathway. For example, if a biofuel replaces a fossil fuel in a transportation or power generation application, the CO_2 that would have been emitted from the combustion of the fossil fuel constitutes an avoided emission. Additionally, switching to a lower-carbon fuel, or capturing and geologically storing fossil derived emissions result in avoided emissions. Negative and avoided emissions reduce our carbon footprint, are important to reach climate goals, and are clearly distinct. While the focus of this report is on negative emissions, in some cases we also estimate the fossil fuel emissions that will be avoided if the negative emission pathway is put into practice.

emitted from airplane fuel. It would be extremely difficult to eliminate all emissions, and it will take a long time to achieve the maximum reductions. We call these **residual emissions.** Activities that reduce the residual emissions shown in Figure 1 will have an identical effect on California's net emissions, and, obviously, those should be pursued.

California's ambition to reach carbon neutrality by 2045 places time constraints on technology options as well—we may not be able to replace emitting technologies, like internal combustion engines, completely by 2045. One approach for handling residual emissions is to create **negative emissions** by physically removing CO_2 from the atmosphere. In this report, we expressly limit the phrase negative emissions to CO_2 that is removed from the atmosphere using, for instance, biomass growth or direct air capture. Negative emissions are distinct from reductions in existing or projected emissions, which are also important and will overlap with negative emissions in resolving the issue of residual emissions. In many cases, reductions in residual emissions and creation of negative emissions occur simultaneously, particularly when waste biomass is used to create both negative emissions and to replace fossil fuels. We will be explicit about those two pathways in this report.

The green wedge in Figure 1 represents the worldwide negative emissions required in order to achieve the well-below 2°C emissions trajectory. (The trajectory shown represents averages of many models that change the rates of electrification, efficiency, and other economic parameters to achieve the 2°C future at the lowest cost to the world economy given today's knowledge of technology options, as summarized by the Mercator Institute [3], [4]). The size of the green wedge grows slowly, representing the realistic growth rates of the technologies required to remove CO_2. The size of the required negative emissions is daunting. Worldwide, we will need to remove around 1 billion tons in 2030, 10 billion tons in 2050, and 20 billion tons in 2100.

It is difficult to estimate California's required negative emissions to reach 2045 carbon neutrality because we lack thorough knowledge of options, particularly beyond 2030. However, California has a detailed plan for reaching 2030 goals of 40% reduction from 1990 levels [5]. Executive Order B-30-15 and SB 32 extended the goals of AB 32 to 2030. Figure 2 outlines the major approaches and targets for those approaches in California's plan. Figure 3 shows a simple extrapolation of the rate of decrease from 2020 to 2030 to 2045, and shows this rate does not yield carbon neutrality. This is consistent with the global evaluations for carbon neutrality that are represented in Figure 1—roughly 20–25% of the current emissions will still be residual emissions by 2045 without additional action. The most immediate path to achieve carbon neutrality may be to offset the residual emissions by negative emissions, which uses either natural or man-made means to remove CO_2 from the atmosphere.

By continuing to reduce residual emissions after 2045, the State could become carbon negative, which will in part address the worldwide deficit created by our slow response to global warming.

Efforts to achieve negative emissions fall into two basic categories [4]: those that rely on plants to absorb CO_2 from the atmosphere, and those that do not. Other authors distinguish between natural methods and man-made options. There is much overlap between these options, but we maintain those distinctions for consistency with other reports, yielding three major categories: natural approaches, biomass approaches, and direct air capture.

Goals of this Report

This report outlines California's major options for achieving negative emissions. Our goal was to determine the probable cost and available capacity of the approaches most likely to be widely available in 2045. It is important to note that while this report targets full deployment of these approaches by 2045, the same negative emissions benefits can be achieved much sooner with more rapid deployment. The scientific literature is just beginning to outline these promising technologies. Figure 4, from the Mercator Institute [3], outlines the major categories. We evaluated five of their major classes: reforestation, soil carbon, biochar, bioenergy with carbon capture and storage, and direct air capture. We had enough information to determine the approximate available volumes and costs for California. A sixth category, enhanced weathering, may be very applicable to California, but there is currently not enough information available to compare it effectively to the other options. Ocean fertilization options were not considered for California since they did not clearly fall into California's realm of actionable solutions.

Since negative emissions technologies are all in their infancy, it is not possible to conduct a conventional engineering analysis. We divided the problem into two major categories:

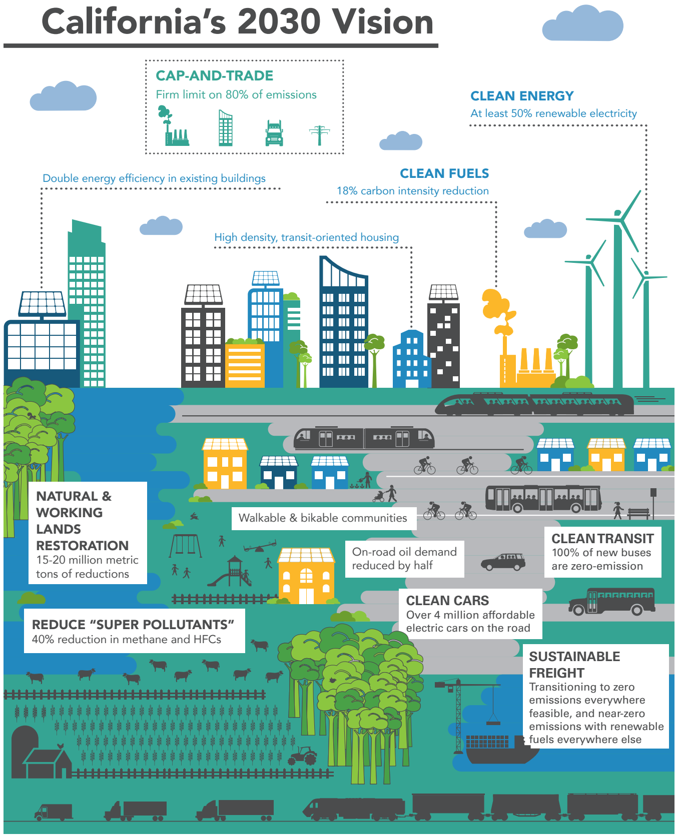


Figure 2. *Main elements of California's 2030 plan to reach 40% net reductions from 1990 levels. From California Air Resources Board 2017.*

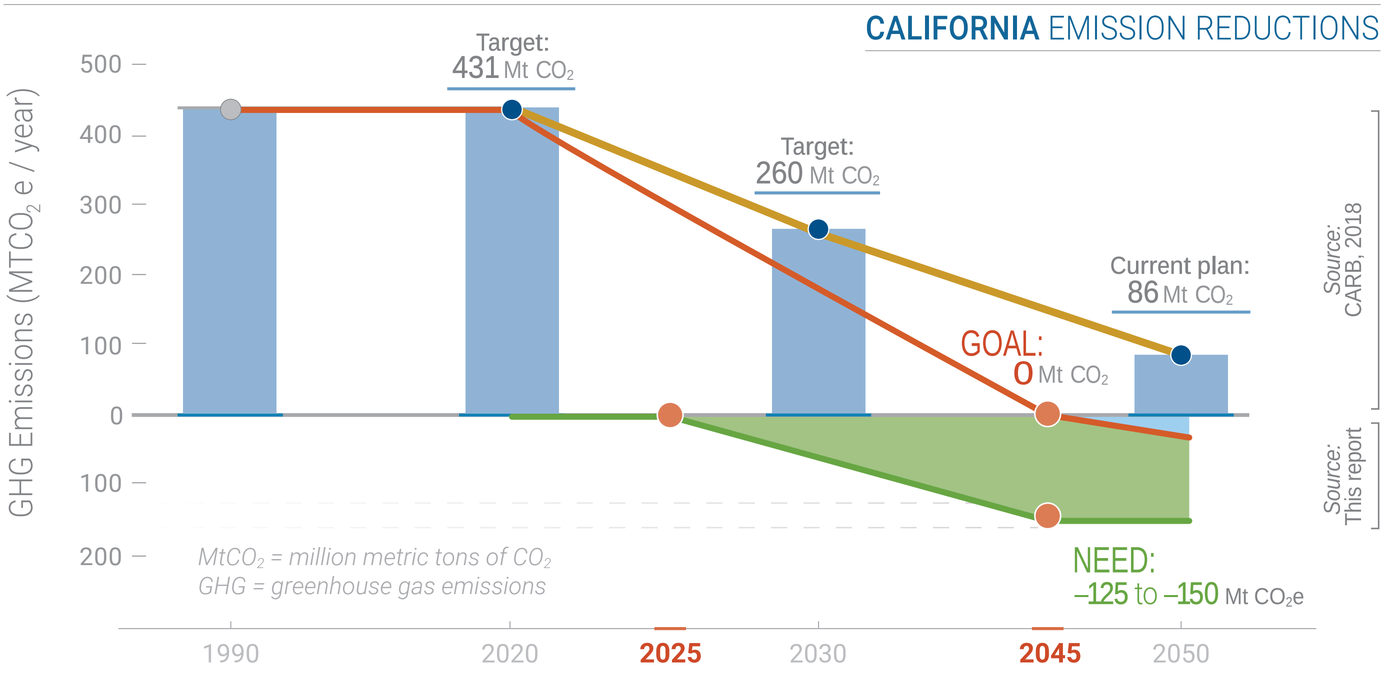


Figure 3. *Goals of California's emissions plan extrapolated to 2045 (CARB, 2017) with negative emissions estimates from this report. (https://ww3.arb.ca.gov/cc/scopingplan/meetings/070819/carb_cn_industry.pdf)*

GHG = greenhouse gas emissions, $MTCO_2e$ = gigaton of CO_2 equivalent

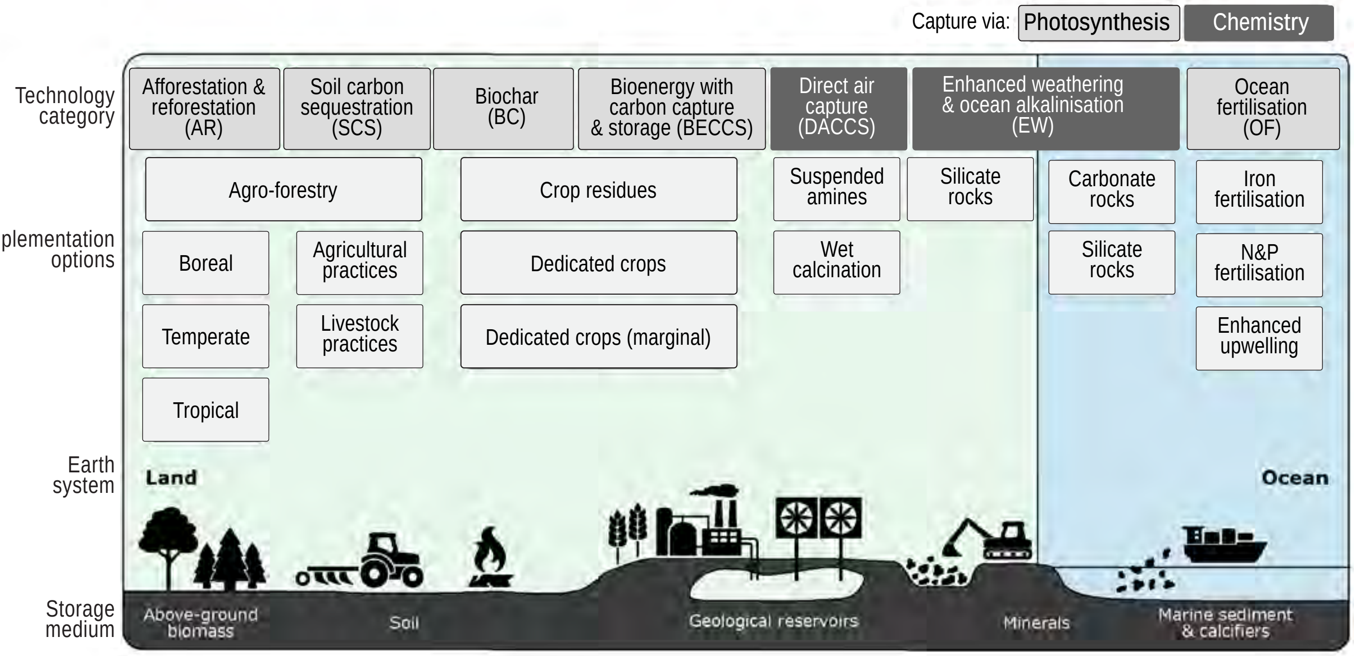


Figure 4. *Available classes of negative emissions technologies that were considered for this report. For applicability to California, the first five were evaluated in detail (afforestation and reforestation, soil carbon sequestration, biochar, bioenergy with carbon capture and storage, and direct air capture). From Minx et al., 2018*

resources that can be used for negative emissions, such as biomass, underground storage capacity, and geothermal heat, and technologies that can be used, such as bioenergy with carbon capture and storage, and direct air capture.

Resources

Biomass solutions are limited by the available amount and location of the material to be utilized and can be categorized as existing sources (such as waste agricultural material and trash) and new sources, such as crops grown specifically for energy use (like switchgrass). While purpose-grown crops could be important in the future, we specifically excluded them from this report because we are unable, within the scope of this effort, to identify all the accompanying effects such as impacts on food availability and water use. We have only considered existing biomass sources, and the change in the amount of those sources that we can predict until 2045. We recognize that policies that value CO_2 negative emissions, such as the California Low Carbon Fuel Standard may encourage new supplies of biomass to become available for purely economic reasons. We have not attempted to quantify this effect, although it may be significant.

Storage will be vital for negative emissions. After we remove CO_2 from the atmosphere by any means, it must be permanently kept out of circulation. The definition of permanent is of great interest here, and we consider all forms of storage that significantly retard the return of the CO_2 to the atmosphere, such as geologic storage, and those that create an active stock-and-flow storage of carbon, such as soil carbon and trees. All three of these solutions have fundamental limits in their total California capacity, and they have limits in the rate in which carbon can be added to these stores. We have attempted to outline those limits, drawing on the work of the State and others for most of the forest data, and making our own detailed analysis of the soil and geologic storage capacity of the State.

Energy may be generated using biomass resources or required in the case of direct air capture approaches. We have analyzed the overall amounts and costs/value for energy in terms of today's energy costs, and our estimates of them in 2025 and 2045. The carbon content of those energy resources is extremely important, since California's negative emissions need is driven by the residual emissions shown in Figure 3. We have assumed that zero-carbon electricity will be widely available in 2045 as specified by California law, and that some fossil fuel will still be in use in 2045 and be available to be displaced by fuels from biomass. Thus, negative emissions technologies that generate electricity are assumed to have no additional effect on residual emissions, while liquid fuel substitutes containing biogenic carbon can displace fossil fuel use in 2045. However, we consider these fuel replacements to be reductions in residual emissions, and not negative emissions.

Technologies

The negative emissions approaches outlined in Figure 4 can be implemented by a number of specific technology options. We have attempted to understand the benefits and costs of all of these options that are in commercial use or development, and of those that we could reasonably estimate the costs for deployment. Where possible, we are informed by the costs provided by developers, but with our own final evaluation and engineering judgment. Some technologies, like carbon mineralization, do not have enough information for even a rough estimate. These are discussed as future options, but not quantified.

Approaches for biomass conversion include those that create long-lived carbon but no liquid fuel (torrefaction and simple biochar processes), those that create liquid fuels (pyrolysis and gasification) and those that create the gaseous fuels H_2 and CH_4 (anaerobic digestion, pyrolysis and gasification), as well as hybrids of those technologies. All of these create CO_2 at the time of conversion, which can be captured and stored permanently. The carbon-containing fuels can also be burned in a later energy process in which CO_2 capture is added to recover the CO_2. We consider the carbon footprints and costs of all of these approaches.

Recycling, or utilization, of CO_2 has two major approaches that store carbon for long periods: creation of concrete and building materials, and creation of long-lived chemicals like polymers [6]. While carbonated concrete formulations can contain significant amounts of CO_2, the product is not carbon negative since significantly more is released from fossil resources (limestone) during formation of the cement. Therefore, we have not included it as a negative emissions sink, although it is a very important emissions reduction approach for California. Creation of the precursors for polymers is not currently an industry in California, so we also did not consider it. A number of technology options for creating solid materials to replace gravel and stone in building materials are being developed today but did not have sufficient information for us to evaluate their cost or applicable volumes. We consider some of these technologies in the section on possible future options for California.

Transportation technologies are likely to be extremely important for California's implementation of negative emissions options. We considered pipeline, truck, and rail transport of CO_2 and biomass.

System Issues

Negative emissions is never a single technology issue. There must be a system of interlinked CO_2 sources, processes and treatment, transport, and final disposition, and that system is always linked to other critical issues such as food, criteria pollutants, and land use. Similarly, the options for negative emissions approaches can be in conflict with each other, particularly over biomass availability and land use. We have attempted to bring all these issues to the fore, recognizing that extensive further study of each is required to make final decisions at the scale California faces for true carbon neutrality.

Natural systems are always the first option for negative emissions, both due to their concomitant advantages (soil health, ecosystem services) and to their generally lower cost. A primary system issue for natural systems is that carbon is in flux over the time scale that we must manage it for climate purposes. Forest carbon is a particularly difficult topic since the time scale for forests to recover carbon (growth) is much longer than that for carbon loss (cutting or fire, for instance). We have relied upon reports from the State and others utilizing the US Forest Service models [7] to inform our system evaluation of the net benefits of forest carbon management. Natural systems have the advantage that their system issues are perhaps the most simple, with the source of CO_2 being the atmosphere, and the ultimate sink being the natural system itself.

Processes that use the various forms of biomass available to California have the most complex system issues. We have accounted for the costs and greenhouse gas impacts of collecting the biomass (when it was not previously collected for another purpose, like municipal trash), transporting it to a processing site, processing it to storable carbon (biochar or CO_2) and fuel (not all biomass processes make fuel), and then transporting the storable carbon to its storage site. Except for renewable natural gas pipelines, we do not account for any transport of fuel created in the process.

Transportation of both biomass and CO_2 can have a significant impact on cost and greenhouse gas footprint. Here we evaluated a number of options, reflecting the fact that it may take a long time to implement low-cost options like pipelines for CO_2 and that there is value in starting some processing with less-optimal transport, especially trucking. CO_2 storage sites are strongly constrained by the geology of California, so transporting CO_2 to the most appropriate sites is a significant constraint on the optimal solution set.

For biochar there are difficult system issues of the lifetime of the biochar in soil, and the optimal soils in which to place biochar. Many biochar developers assume a significant sale value for biochar. We did not, because of the uncertainty and because we were unable to predict the transportation costs associated with unknown application sites. We have simply assumed that biochar is placed in soil near where it is created, thereby obtaining the maximum climate value but perhaps at a higher cost than might be obtained in an optimal system.

Costs

Our explicit goal here is to generate accurate costs for the removal of CO_2 from the atmosphere. Accordingly, we added up all of the processes and equipment needed for each pathway, at a scale recommended by developers of that pathway. We gathered capital costs for similar equipment from literature and scaled up to represent our system. Operating costs are calculated based on mass and energy balance of different pathways. We use a discounted cash flow rate of return method to calculate the costs and break-even point price for our products.

We then subtract the current market value for our products (Figure 5) from the total product cost, such as liquid fuel, hydrogen, natural gas and electricity. The remainder is the cost of removing the CO_2 from the air. As such our values can be extremely sensitive to the cost of capital, and to the value of products. These are subject to adjustment by policy, so we present our costs **without any policy adjustments** (e.g. 45Q tax credit, low carbon fuel standard carbon credit, etc.).

Since some of the technology options discussed here are not yet commercialized at scale, we have developed a uniform approach for applying learning curves to the costs in 2045 and beyond for direct air capture and pyrolysis for liquid fuel production. Those learning curves are based on the number of process units deployed, assuming an exponential deployment from 2025 to 2045 sufficient to meet 2045 demand. Learning curves are likely to be the most accurate for technologies where the representative unit is well known today, which will be replicated at consecutively lower cost in the future. The best case is when the number of operating units doubles, such as when two facilities are expanded to four. As such, direct air capture is very appropriate for this analysis since there are demonstration-scale units operating today and there are well-established plans for large-scale units of known size. Some of the biomass conversion systems in our report are less constrained by current plans for either size or cost, and so their future costs are less predictable. Gasification, however, is very well established and costs are unlikely to be changed significantly by additional California plants.

For each pathway that leads to negative emissions (three generalized negative emissions pathways from CO_2 in the atmosphere to sequestration are shown in Figure 6) we have estimated the total volume of CO_2 processable by that method, and the cost for the negative emissions aspect of the process. We then organized them by increasing cost, taking care to divide the processes when a single process, say forest

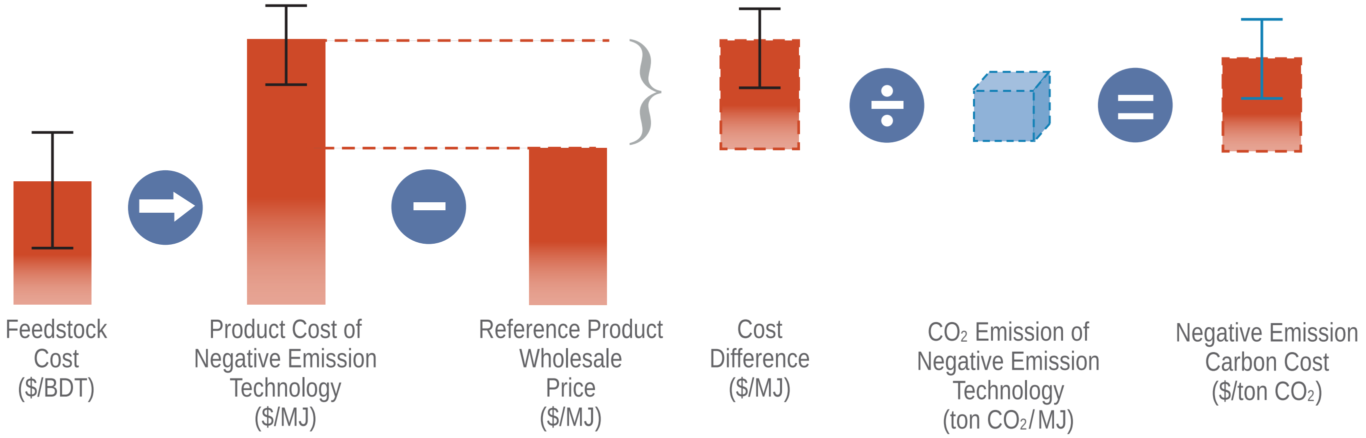


Figure 5. *Costs for biomass-based negative emissions consider the feedstock and processing costs to produce a fuel, and the current market value of that fuel, as part of the total cost of capturing CO_2 for permanent storage.*
BDT = bone dry ton, MJ = megajoule.

logging waste processing to hydrogen via gasification, was the lowest cost for some of the source material but not for all. This often occurred due to transportation costs, where large centralized units were appropriate for much of the material, but some was so far from those locations that a different process, like small-scale pyrolysis, was more cost effective for that material.

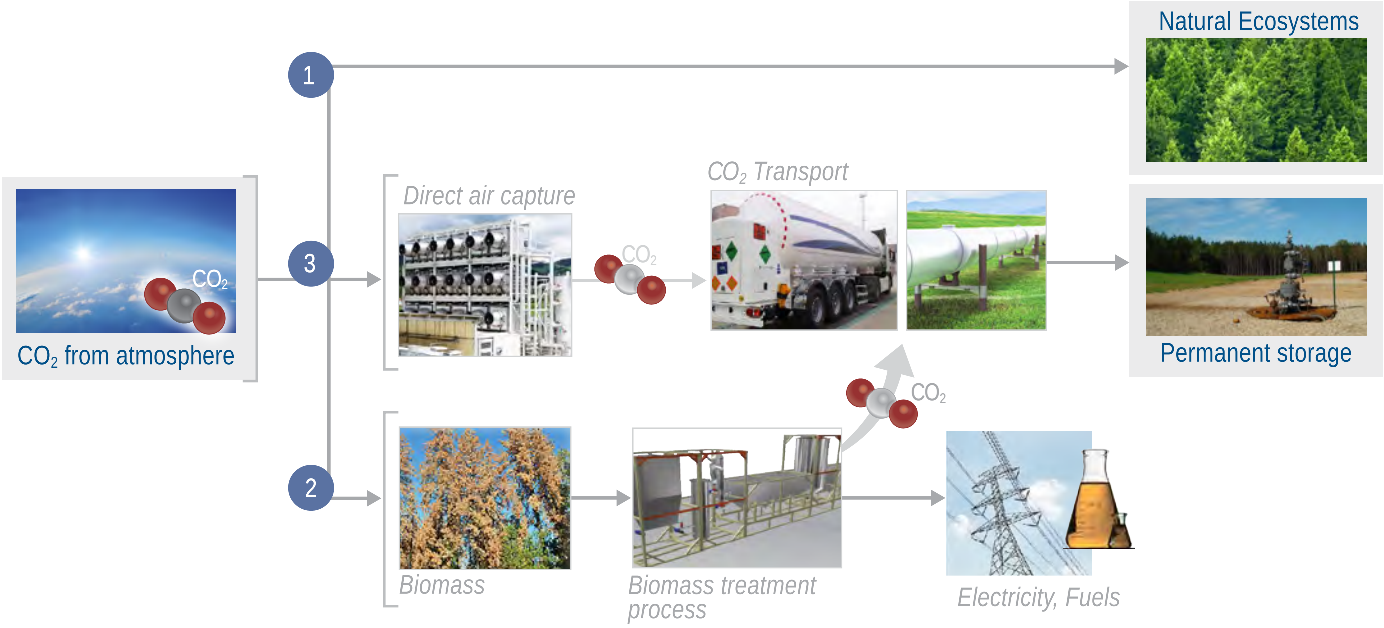


Figure 6. Flow diagram illustrating the three main pathways to negative emissions considered in this report: *CO_2 can be removed from the atmosphere by 1) restoring natural ecosystems, 2) converting waste biomass to electricity and fuels while capturing the CO_2 generated during processing, and 3) and using direct air capture machines.*

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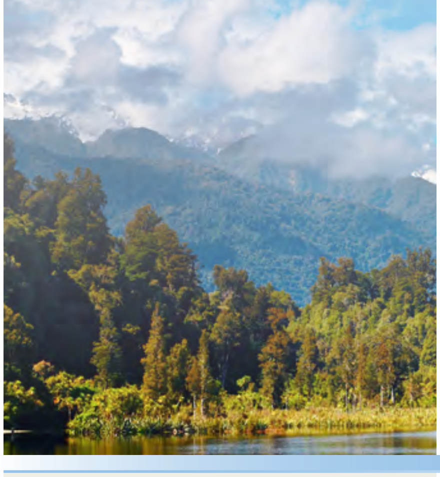
CHAPTER 2

Natural Solutions



SUMMARY

Natural solutions are the first of three pillars in our approach to negative emissions. These approaches seek to capture and store carbon in natural and working lands. Previous studies have estimated the negative emissions potential of these solutions, notably a study by Cameron et al. from which we adapt estimates from forest management practices, restoring freshwater and tidal wetlands, reforesting disturbed areas, and restoring native grasslands. We add to these our own estimates of the negative emissions potential from enhancing soil carbon, using the well-known COMET model and greenhouse gas accounting system. We use published costs for each natural solution and calculate a weighted average for this negative emissions pillar. The quantity and length of time that carbon can be stored in natural systems, especially soil, is more uncertain than for the other pillars. We discuss the sources of uncertainty and how the estimates may be improved.

Key Findings

Estimated costs and quantities of negative emissions from natural solutions are summarized in Table CS-2. Further simulations and field-scale experiments in California are needed to more accurately predict these potentials and more firmly establish the ones with the greatest carbon benefit. Natural solutions have important co-benefits to air and water quality, ecosystem and soil health, resilience to climate change, and protection of life and property through fire reduction.
A challenge to natural solutions is that they are limited by the amount of available land and that their potential to draw down carbon may saturate over time. Soil carbon potential estimates may prove higher after further study.

Scope of Chapter

Methods to remove CO_2 by increasing the carbon stored in plants and soils. These approaches include:

- Changes to forest management, such as extending rotation intervals and removing diseased or suppressed trees
- Reforestation of sites disturbed by wildfire
- Grassland restoration at sites cultivating annual row crops
- Restoration of tidal and freshwater wetlands at sites previously used for corn or irrigated pasture
- Compost amendments to grasslands (including range lands) and crop lands
- Changes to plant cover reducing fallow periods
- Planting perennials
- Biochar as a soil amendment

Table CS-2. *Summary of negative emissions potentials from natural and working lands. All Natural Solutions cost is a weighted average.*

Strategy	Average Cost ($/ton CO_2e)	Negative Emissions Potential in 2045 (million tons CO_2e/yr)
Reforestation	16.4	4.9
Tidal marsh restoration	79.0	0.9
Freshwater wetland restoration	440.5	0.2
Grassland restoration	72.5	0.1
Changes to forest management	0.8	15.5
Soils	15.0	3.9
All Natural Solutions	11.4	25.5

Introduction

Natural and working lands cover over 90% of California, and come in a remarkably wide variety, including farmland, rangeland, forests, woodlands, wetlands, coastal areas, grasslands, shrubland, riparian areas, and urban green space [8]. These lands can clearly act as carbon sinks given the living plant matter they host, but they can also act as carbon sources when they burn, are cultivated intensively using conventional fertilization and tilling practices, or are converted from their natural state to another land use. As such, the imperative to prevent or reduce emissions from these lands comes hand in hand with the potential to manage them as net carbon sinks.

This chapter presents the most authoritative or commonly cited existing estimates for negative emissions from natural and working lands, and also attempts to quantify some natural solutions that do not have reliable estimates yet.

Forests, Wetlands and Grasslands

In presenting estimates for negative emissions from natural and working lands, we note the distinction between negative and avoided emissions. Measures that, for example, reduce wildfire severity, or conserve wildlands from conversion to agricultural or urban use fall under the definition of avoided emissions in this report. That is, they prevent additional carbon from reaching the atmosphere, but do not physically remove carbon from it. The primary purpose of this report is to estimate the negative emissions potential for the State, while also pointing out avoided emissions potential where appropriate. As such, this chapter focuses on measures and interventions that result in increased sequestration. All forms of reforestation or revegetation fall under negative emissions and are not accounted for in any other process categories.

Independent Estimates

The source for our estimates is a modeling study by Cameron et al. [9] that examined the potential role for ecosystem management and land conservation to contribute to California's climate mitigation goals. The authors disaggregate avoided emissions from increased sequestration, and here we present the latter only since it is tantamount to negative emissions. Table 1 shows a summary of this subset of interventions. We exclude compost amendments to grasslands, which are also mentioned by Cameron et al., as we use our own estimates for that later in this chapter.

In the Chapter 3, we examine how much forest biomass waste can be sourced and gathered for use in negative emission applications.

While we cannot rule out the possibility of overlap between our forest biomass estimates in Chapter 3 and the Cameron et al. forest management estimates presented here, we note that the two are fundamentally complementary. Chapter 3 biomass estimates are defined by the amount of small, non-merchantable trees which could be removed from all timber land in California for the purpose of fire risk reduction. The Cameron et al. estimates of changes to forest management

Table 1. *Interventions described in Cameron et al.*

Intervention	Description
Changes to forest management	Changes to the way a forest is managed to increase carbon stocks above what would have happened if such changes had not occurred (e.g., increasing harvest rotation length, maintaining stocks at a high level, increasing productivity by removing diseased or suppressed trees). Negative emissions are based on ongoing sequestration of carbon, including the transfer of harvested carbon to durable wood products.
Reforestation of disturbed sites	Active regeneration of forest on sites that experienced a significant disturbance from wildfire. Negative emissions are based on ongoing sequestration of carbon.
Wetland restoration: corn to managed wetlands	Restoration to managed freshwater wetlands from peatland sites previously converted for the cultivation of corn. Negative emissions are based on ongoing sequestration of carbon in managed wetlands.
Wetland restoration: pasture to managed wetlands	Restoration to managed freshwater wetlands from peatland sites previously converted for use as irrigated pasture. Negative emissions are based on ongoing sequestration of carbon in managed wetlands.
Wetland restoration: pasture to tidal wetlands	Restoration to tidal wetlands from peatland sites previously converted for use as irrigated pasture. Negative emissions are based on ongoing sequestration of carbon in tidal wetlands.
Wetland restoration: corn to tidal wetlands	Restoration to tidal wetlands from peatland sites previously converted for the cultivation of corn. Negative emissions are based on ongoing sequestration of carbon intidal wetlands.
Grassland restoration: annual row crops to grasslands	Restoration of grasslands from non-shrub/-tree crop cultivation on sites that were previously grasslands or have the natural capacity for such cover. Negative emissions are based on ongoing sequestration of carbon in grassland soils.

are primarily based on existing carbon offset projects, which emphasize the retention of large trees on managed timber land (e.g. extended rotations). For this reason, most of the carbon sequestration counted by Cameron et al. would be in large trees, which we exclude from our biomass availability estimates.

There may also be some relation between the estimate we use for sawmill residue in the following chapter and the proposed changes in forest management by Cameron et al., if these changes result in decreased sawmill output, but we have not attempted to adjust the former for reasons of clarity and simplicity.

The interventions above vary as to their relative contribution. Using the estimates presented in Cameron et al.[1], we calculated the annual figure for increased sequestration (and therefore negative emissions) from the interventions listed above, as 21.6 million tons CO_2 equivalent per year in 2045.[2] We use estimates for the "Ambitious" scenario, which is equivalent to a technical potential estimate, limited by available land and historical rates of implementation.

Cameron et al. do not present cost estimates for these interventions, but we relied on other publications for cost figures. The relative contributions, costs, and sources are shown in Table 2 below.

Table 2. *Relative contributions and cost estimates for natural solutions.*

Intervention Type	Increased Sequestration by 2045 ($MtCO_2e$)	Cost ($/$tCO_2e$)	Source
Reforestation	46.0	16.4	USDA NRCS EQIP [10] , Next10 [11]
Tidal marsh restoration	12.1	79.0	Zentner et al. [12]
Freshwater wetland restoration	3.0	440.5	Zentner et al. [12]
Grassland restoration	1.4	72.5	UC ANR Publication 8575 [13]
Changes to forest management	227.8	0.8	Galik et al. [14]

$MtCO_2e$ = million tons of CO_2 equivalent

The costs presented in the sources referenced in Table 2 are mostly in terms of dollars per acre. We converted those to dollar-per-ton-of-CO_2 terms by using the annual implementation area data and the cumulative sequestration by 2050 data in Cameron et al., and also adjusting for inflation.[3] Costs for changes to forest management in Galik et al. were stated in dollar per ton terms, and we used the sum of mean production and transaction costs for Extended Rotation project type in the Pacific Southwest.[4] As can be seen, some of the costs are substantial, as in the case of freshwater wetland restoration, whereas in the case of changes to forest management to extend rotations, little cost is incurred. Consistently with our approach on competing uses for feedstocks in this report, we do not count the foregone timber revenues from these extended rotations.

Later in this chapter, we combine these cost estimates and relative contributions to negative emissions (increased sequestration) with our own estimates for how much carbon could be stored in California's soils to calculate a weighted average cost for the entire family of natural solutions. This weighted average is based on relative contributions to negative emissions in 2045.

2030 State Natural and Working Lands Climate Change Implementation Plan

Several state agencies in California collaborated over several years to compile the "California 2030 Natural and Working Lands Climate Change Implementation Plan," which is a blueprint for action on natural and working lands that aims to maximize climate benefits and serve other important environmental and ecological objectives. The plan, summarized in Table 3, focuses on "just a piece of [the overall] opportunity – specifically, the scope and scale of a suite of State-supported land management, restoration, and conservation activities that can be pursued now to help change the current emissions trajectory and move the sector closer to becoming a resilient carbon sink." We note that the Plan's estimates represent what could be achieved under state jurisdiction, programs, and incentives. The overall potential includes broader land ownership and levers for action and is larger. Nonetheless, this estimate is useful because there is a long-established desire and commitment on the State's part to pursue relevant action.

Specifically, the Plan sets the following goals to be achieved through state-funded activities:

- Quintuple the acres in soil conservation practices;
- Double the pace and scale of forests managed or restored;

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[1] See Cameron et al. 10.1073/pnas.1707811114, Supplemental Information, Table S5.

[2] We use 2050 estimates as presented in Cameron et al. for 2045, which is a reasonable approximation given the uncertainty in the estimates.

[3] Cameron et al. 10.1073/pnas.1707811114, Supplemental Information, Tables S2 and S5 respectively.

[4] Galik et al., Supplemental Information, Tables S1 and S2.

- Triple the pace of reforestation of oak savannas and riparian areas; and
- Double the rate of wetland and seagrass restoration.

The Plan uses a combination of CALAND and COMET-Planner (CarbOn Management and Emissions Tool) to estimate the greenhouse gas benefits for two scenarios: scenario A (less optimistic) and scenario B (more optimistic). The results shown in Table 4 are reported relative to the baseline, and not in terms of absolute emissions. The interventions contemplated are a mix of negative and avoided emissions.

Assuming Scenario B, which corresponds to implementation over a larger and more ambitious acreage, the results imply that the State can achieve 83.1 million tons of CO_2 worth of combined negative and avoided emissions by 2045. The results are positive in the early years, implying an emissions increase relative to the baseline, due to fuel reduction efforts (such as prescribed burns) that pay off in the later years. To derive an average annualized number for 2045, we divide by 25 years. This yields approximately 3.3 million tons of CO_2 per year as the State-controlled contribution to negative emissions from natural and working lands. We do not have the means to disaggregate negative from avoided emissions in this number. Rather, we use it as a general reference point for what current state programs and frameworks could deliver in the natural and working lands sector.

Table 3. *Summary of Interventions in the 2030 State Natural and Working Lands Climate Change Implementation Plan.*

Intervention	Description
Conservation: avoided conversion of natural and working lands	50–75% reduction in annual rate of conversion by 2030.
Forestry: improved forest health and reduced wildfire severity, enhanced carbon in forested ecosystems, biomass utilization.	Prescribed fire, thinning, understory treatment, less intensive forest management, additional 50% of slash diverted from pile burn/decay to other uses.
Restoration	Riparian, oak woodland, coastal wetland, Delta wetland, meadow and seagrass restoration. Urban forest expansion.
Agriculture: agroforestry, cropland management, compost application	Silvopasture, hedge row establishment, windbreak establishment, riparian forest buffer, riparian herbaceous cover. Cover cropping, mulching, no-till farming, reduced-till farming. Compost application on annual cropland, perennial cropland, non-irrigated cropland, irrigated pasture.

Table 4. *Summary of Cumulative 2030 and 2045 results from the 2030 State Natural and Working Lands Climate Change Implementation Plan.*

Scenario	Acres implemented by 2030	Million metric tons of CO_2e: 2030	Million metric tons of CO_2e: 2045
Scenario A	2,742,000	12.4	-84.2
Scenario B	4,306,000	35.9	-83.1

Negative Emissions from Forests, Wetlands and Grasslands Conclusion

Based on the above, we consider 21.6 million tons CO_2 per year to be a reasonable estimate of the negative emissions that could be realized from the natural solutions outlined by Cameron et al. (excluding composting) by 2045. The cost for these interventions varies widely, as does their relative contribution to the total.

We now take a close look through primary research at how much carbon could be stored in California's soils, and subsequently present a weighted average cost for all of these interventions and practices in aggregate at the end of the chapter.

Soil and Biochar

Lawrence Livermore National Laboratory researchers have been conducting extensive primary research to estimate the amount of carbon that could be stored in U.S. soils. We leverage the effort in this report to obtain a bottom-up estimate for California.

Assessing Potential for Carbon Sequestration in California's Soils

Soils have lost approximately 130 billion metric tons of organic carbon (477 billion metric tons of CO_2 equivalent) to the atmosphere globally since the advent of modern agriculture [15], [16]. Reversing soil organic carbon losses by altering land management would sequester atmospheric CO_2 while also potentially delivering gains in soil fertility [17]. Estimates of the near-term carbon storage potential of agricultural soils are in the range of approximately 0.08–1.85 metric tons of carbon per hectare per year, or 0.3–6.8 tons of CO_2 equivalent per hectare per year [18], [19]. In theory, increasing soil carbon stocks globally at these rates could sequester 1–4 billion tons of carbon (3.7–14.7 billion tons of CO_2) per year, with the potential to offset global temperature increase [18]–[20].

To achieve this, a broad range of land management practices—including changes in plant cover, organic amendments, and reduced tillage—have been proposed [21]. However, the long-term climate benefit of these practices is uncertain given that soil carbon stocks saturate over time while increases in soil carbon may be accompanied by emissions of nitrous oxide and methane [22], [23]. In this section, we evaluate the negative emissions potential and associated uncertainty for a range of soil carbon management practices in California. Some of these practices were considered separately by Cameron et al. [9]; here we consider a more extensive application of these practices by 2045.

Several strategies aim to increase carbon inputs to soil [24]. These practices include changes to plant cover that reduce the duration of fallow periods (cover cropping, conversion to perennials) [21], and increasing the fraction of plant carbon that is delivered belowground (conversion to deeply-rooted perennials) [21], [25], [26]. Alternatively, increased carbon inputs may be derived from exogenous organic amendments to the soil: organic waste, compost, and biochar [21], [27]–[29]. Adding exogenous organic amendments to soil has the primary effect of redistributing biologically fixed carbon that has already been temporarily removed from the atmosphere, and thus does not at face-value represent negative emissions [30]. However, organic amendments can increase plant productivity in-situ, and a small fraction of added amendment carbon may become associated with soil minerals and persist as soil organic matter at decadal to centennial timescales [27].

Increases in soil carbon might also be achieved by reducing the rate of carbon emission from soil. Whether these interventions are classified as negative or avoided emissions depends on whether soils are experiencing a net loss of carbon under current management practices. Here we follow the convention of treating soil carbon gains from reduced carbon emissions as negative emissions, while acknowledging that the boundary between negative emissions and avoided emissions is unclear in the context of land management. Reduction or cessation of tillage in croplands (reduced or no-till farming) is thought to reduce carbon emissions from soil by limiting physical disturbance, potentially making organic matter less accessible to microbial decomposers [31]. Changes from annual to perennial plant cover can also reduce carbon losses by introducing root-derived carbon deeper into soil profiles, where physical disturbance is infrequent and environmental conditions favor carbon persistence [25], [26].

Evaluating the potential for carbon sequestration across different environments is challenging because soil carbon does not represent a stable carbon reservoir; rather, soil carbon stocks are naturally dynamic, and are in a state of continual decline in some managed landscapes [32], [33]. Furthermore, the capacity of soils to respond to management is finite because carbon losses tend to accelerate as soil carbon increases [34], [35]. Consequently, carbon-sequestration rates in soil decline over time and management practices must be sustained in order to maintain finite increases in soil carbon [23]. Soil carbon is not intrinsically persistent; rather, its residence time in soil is an emergent property of interacting environmental factors [36]. All soil carbon management strategies are thus likely to yield different results in different soil types and climates. In addition, management strategies must consider emission of nitrous oxide and methane, which may negate the climate benefits of increasing soil carbon [22], [32].

Biogeochemical models can be used to predict the dynamics of soil carbon accrual and emissions of nitrous oxide and methane over time. Here we use regional-scale estimates derived from the COMET model (http://cometfarm.nrel.colostate.edu/), which is based on the DayCent (Daily Century) soil biogeochemical model [37], [38]. The COMET planner tool has been used to simulate a range of soil conservation practices (Natural Resources Conservation Service Conservation Practice Standards) that correspond to the management strategies considered here [38]. The COMET planner accounts for soil organic carbon dynamics by calculating the difference between soil organic carbon under a given conservation practice and soil organic carbon under baseline conventional management. The COMET planner can also be used to account for nitrous oxide and methane production, producing a global warming potential-corrected emissions reduction coefficient (tons of CO_2 equivalent per hectare per year) that represents the corrected change in carbon storage versus the baseline scenario [38].

We acknowledge that the fundamental assumptions of biogeochemical models like COMET do not reflect current understanding of the biotic feedbacks that govern soil carbon dynamics [39]–[41]. Models with a first-order structure like COMET tend to overestimate transfer of carbon into long-lived pools, and consequently may systematically overestimate carbon storage potential in soils [42]. More complex second-order soil carbon models better capture the biological feedbacks that govern soil carbon persistence and produce predictions that diverge from traditional models—but are also very difficult to parameterize [41]. Given the uncertainty associated with biogeochemical models, field-scale experiments conducted in California are ultimately essential to prioritizing soil carbon management strategies [43].

Methods for Soil Carbon Estimates

We obtained predictions using the online COMET planner tool, which reports emission reduction coefficients values associated with different conservation practices at the county level across the United States. COMET planner predictions are derived from individual model simulations carried out at approximately 100 sample locations within land units defined by United States Department of Agriculture Major Land Resource Areas [38]. At each sample point, land use is determined using United States Department of Agriculture National Agricultural Statistics Service land cover data for 2009–2015 [44]. Mean, minimum, and maximum emission reductions values are reported for the sample associated with each resource area. COMET planner outputs represent a 10-year average emissions reductions and are not considered reliable beyond this time horizon given the potential for soil carbon stock to saturate at longer timescales [38].

We compared five Conservation Practice Standards that we considered representative of soil organic carbon-management strategies discussed in the context of California agriculture (Table 5). These do not represent an exhaustive set of scenarios; rather they provide a general sense of the magnitude and uncertainty of soil organic carbon gains achievable statewide. We calculated statewide carbon gains by applying the emissions reductions values associated with each conservation practice across land-use maps derived from National Agricultural Statistics Service land cover data from 2017 (Figure 7). These categories included annually cropped farmland, perennials and tree crops, and grassland/rangeland. We did not consider grazed oak woodlands and shrublands as these cannot be readily identified using National Agricultural Statistics Service land-use maps, and the presence of woody biomass may influence the technical feasibility of the conservation practices we considered. United States Department of Agriculture National Agricultural Statistics Service land-use categories were grouped according to preexisting tables [45].

We used COMET model scenarios for compost addition rather than the California-specific model projections for compost addition to soil developed by the California Department of Food and Agriculture Healthy Soil Program and distributed with the COMET planner outputs via the California Healthy Soils Tool. The Healthy Soils Tool projections represent a 3-year simulation [45] whereas COMET planner outputs represent a 10-year simulation. We thus opted for the basic COMET planner projections in order to maintain a consistent timescale across the practices we considered. We note that in both scenarios a substantial fraction of the soil carbon gains observed at three or ten years will not persist at the multi-decadal or centennial timescales relevant to long-term carbon sequestration [23], [32] and stress that longer-term simulations are necessary for projecting the true negative emissions potential of soil conservation practices.

Strategies related to tillage, crop rotation, and amendments (Conservation Practice Standards 328, 340, 345, 590) were applied across 90% of annually cropped farmland. These conservation practices might also be integrated into perennial systems (e.g., cover cropping, planting shade-tolerant

Table 5. *Conservation Practice Standards used to scale emission reductions.*

Conservation Practice Standard	Scemario Applied	Area Applied	Mean ERC (tCO_2e ha^{-1} y^{-1})
CPS 327: Conservation Cover	Convert irrigated cropland to permanent unfertilized grass cover	500,000 acres in the San Joaquin Valley (0.2 Mha)	0.18
CPS 328: Conservation Crop Rotation	Decrease fallow frequency or add perennial crops to rotation	90% of annually-cropped land; 20% of perennially cropped land (1.3 Mha)	0.62
CPS 340: Cover Crop	Add legume cover crop to irrigated cropland	90% of annually-cropped land; 20% of perennially cropped land (1.3 Mha)	0.65
CPS 345: Reduced tillage	Intensive till to reduced till on irrigated cropland	90% of annually-cropped land; 20% of perennially cropped land (1.3 Mha)	0.17
CPS 590: Nutrient Management	Replace 20% of synthetic N fertilizer with compost (carbon to nitrogen ratio 20) on irrigated croplands/pasture	90% of annually-cropped land; 20% of perennially cropped land (1.3 Mha); 90% of rangeland (4.3 Mha)	0.69 (crops) 0.24 (range)

tCO_2e ha^{-1} y^{-1} = tons of CO_2 equivalent per hectare per year, Mha = million hectares, N = nitrogen, ERC = Emissions Reduction Coefficient perennials, or applying compost in orchard alleys), but likely at a lower intensity. We assumed that 20% of the perennial-dominated land area was available for these practices. In grasslands, compost addition was applied across 90% of grassland/rangeland area. Conversion of irrigated cropland to native grassland (Conservation Practice Standard 327) was applied across 500,000 acres in the San Joaquin Valley that may be left fallow in the future to meet California's groundwater sustainability goals [46]. Grassland restoration was modeled by dividing the fallowed area equally among the California groundwater basins in the San Joaquin Valley listed under critical overdraft in 2019 [46]. We consider these estimates separate from the restoration targets in Cameron et al. [9].

Organic amendments may include biomass feedstocks that can be diverted to alternative fates (e.g., combustion, burial, biofuel production, geologic sequestration) [21], [47]. To facilitate comparison with these alternatives, we quantified the feedstock requirements for compost-based management strategies via a synthesis of published values. We quantified feedstock requirements by calculating a soil organic carbon "yield coefficient", equation 1, for feedstock carbon over time across studies.

This coefficient provided a common framework for quantifying the amount of feedstock required to achieve apparent soil organic carbon gains over time, regardless of the timing of feedstock application (i.e., continual additions versus a single dose). Most studies we reviewed described additions of composted feedstock to soil, in which case we included carbon loss during composting in this calculation to facilitate direct comparison with alternative fates for the biomass (i.e., the denominator above represents feedstock before composting). Where the feedstock to compost ratio was not reported, we assumed that 40% of the feedstock carbon was lost in composting [47].

Results

Total emissions reductions from applying all conservation practices equaled 3.9 million tons of CO_2 equivalent per year. The range of uncertainty was considerable for individual conservation practices—minimum estimates showed net positive emissions for 4 out of 6 conservation practices (reduced tillage, cover cropping, restoring fallow land in the San Joaquin Valley, and compost addition to croplands) (Figure 8). If minimum emissions reductions occurred across all practices, total emissions reductions would be-1.9 million tons of CO_2 equivalent per year (positive net emissions) (excluding conservation rotation, which was not supplied with a range). In the best-case scenario, total emissions reductions were 10.6 million tons of CO_2 equivalent per year (conservation rotation excluded). This range reflects geographic variation in the biophysical parameters supplied to COMET and does not incorporate underlying scientific uncertainty regarding the model assumptions; consequently, we consider this range an underestimate of total uncertainty. Furthermore, we stress that the COMET simulations only represent the average of a 10-year simulation; longer-term simulations are ultimately required to estimate the persistence of soil carbon gains.

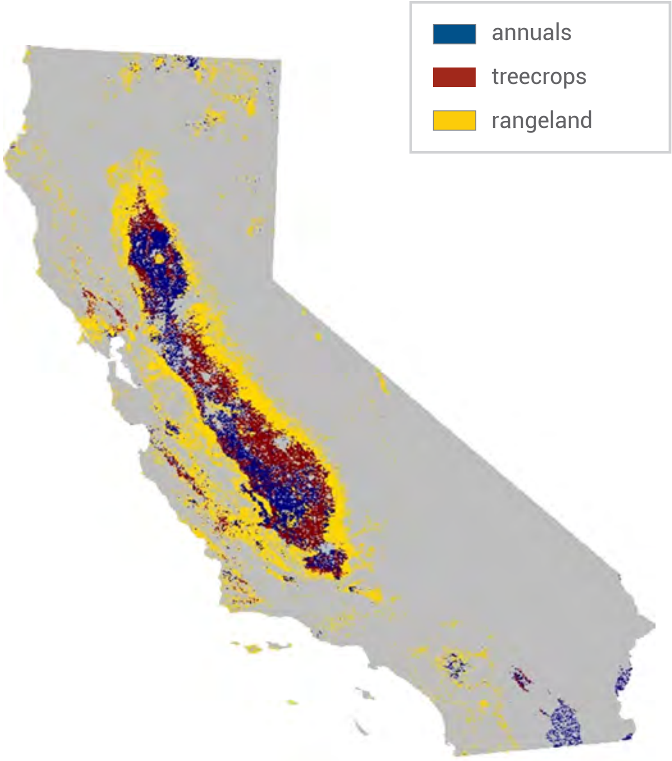


Figure 7. *Distribution of lands considered when scaling emissions reductions*

Tillage and Cover Cropping

The emissions reductions reported by COMET are generally consistent with global meta-analyses and California-specific experimental and modelling investigations. For instance,

Equation 1. *Soil Organic Carbon Yield Coefficient*

$$\text{Yield Coefficient} = \frac{\text{Cumulative Change in Soil Organic Carbon}}{\text{Cumulative Amendment Added}}$$

the comparative low emissions reduction for reducing tillage (0.18 tons of CO_2 equivalent per hectare per year) is consistent with a meta-analysis that showed redistribution of carbon within soil profiles following cessation of tillage, but no net gains on average [48]. Meta-analysis also suggests potential gains from cover cropping that are comparable to the COMET estimates at 1.17 tons of CO_2 equivalent per hectare per year [49]. However, long-term experimental data in California's Central Valley showed net loss of soil organic carbon at a rate of-2.34 tons of CO_2 equivalent per hectare per year under cover cropping when the entire soil profile is considered [43], which is more consistent with the minimum value reported by COMET. This divergence highlights the need for long-term field studies of soil organic carbon management in California that consider carbon inventories at the soil-profile scale.

Planting Perennials

Soil organic carbon management strategies related to establishment of perennial cover (Conservation Practice Standard 328 and 327) differed substantially in their effects. The emissions reduction simulated by COMET for converting irrigated farmland to grassland in the San Joaquin Valley was quite low (emissions reduction = 0.18 tons of CO_2 equivalent per hectare per year). This rate is considerably smaller than global estimates for conversion of farmland to grassland (3.18 tons of CO_2 equivalent per hectare per year) [50]. Furthermore, observations in coastal California grasslands suggest that conversion of native perennial grassland to shallow-rooted annuals has resulted in large carbon losses, implying a large potential for soil organic carbon gains in restored land [51]. However, the San Joaquin Valley has an arid climate and many upland soils in the valley are classified as desert soils, which do not support naturally productive vegetation and tend to have low carbon stocks. Irrigation might have the effect of increasing carbon inputs by boosting productivity in these soils. For instance, long-term data from the San Joaquin Valley shows net accrual of carbon even under conventional farming practices [52].

The comparatively high emissions reductions for conservation crop rotation (0.62 tons of CO_2 equivalent per hectare per year) suggests that rotating deeply rooted crops in irrigated farmland may result in carbon gains. In addition, planting perennials may have unique features because this strategy targets deeper soil horizons as the site of carbon sequestration. Soil carbon residence time increases with depth across all ecosystems and soil types that have been surveyed, indicating increased potential for carbon persistence at depth [53]. Even if the near-term rate of carbon sequestration via deep roots is small, the overall capacity of deep soil horizons is likely to be relatively large because deep horizons contain little carbon to begin with and are thus likely to be far from saturation. More soil-profile-scale field research is required to fully evaluate the rate at which deep soil carbon accumulates under common perennial crops in California.

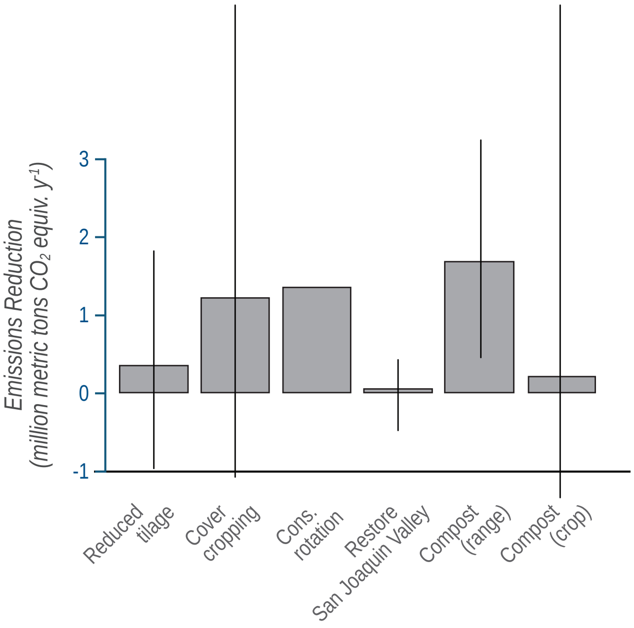


Figure 8. Total emissions reductions associated with each Conservation Practice Standard. *Bars show means; lines indicate minimum and maximum values. Negative values indicate net positive emissions. The conservation rotation scenario (Conservation Practice Standard 328) was not supplied with an uncertainty range by COMET Planner and so only the mean value is shown. MMT CO_2e y-1 = million metric tons of CO_2 equivalent per year*

Compost Addition

The mean emission reduction for compost addition was 0.24 tons of CO_2 equivalent per hectare per year in rangelands and 0.69 tons of CO_2 equivalent per hectare per year in croplands. Direct comparison with published values is challenging in this case because emissions reductions from compost addition depend on the quantity of feedstock added. Average soil carbon accumulation rates as high as 4.1 tons of CO_2 equivalent per hectare per year were observed from a combination of composted manure addition and winter cover cropping over 0–19 years in the Central Valley [43]. However, carbon addition rates in this study were higher than the rate implied by COMET planner (100% of nitrogen supplied as compost versus 20%). Average emissions reduction rates from one-time compost additions in rangelands have been modelled at 0.42 tons of CO_2 equivalent per hectare per year 0–15 years after addition [54], which is double the estimate given by COMET for applying compost to pasture. This divergence may reflect the fact that COMET planner simulates pasture—which is intensively managed—rather than rangelands [55]. The quantities and timing of compost addition also vary between the two cases.

Soil organic carbon increases from compost addition are time dependent—both the absolute rate of carbon sequestration and the feedstock yield decline over time. Initially (0–3 years after addition), feedstock yields reflect carbon losses during composting (before addition of compost to the soil), which we assumed releases 40% of feedstock carbon (Figure 9). At longer timescales the yield decreases, approaching 10% at 100 years. This is likely an overestimate of feedstock carbon remaining after 100 years because the values we assessed at that time point are from: (1) first-order model simulations, which tend to overestimate transfer of carbon to slow-cycling pools [42]; (2) long-term experimental data from Rothamstead, Britain, where farmyard manure was added continuously and soil organic stocks at 100 years thus partly reflect recent additions [35]. The initial application of amendment carbon to soil represents redistribution rather than sequestration—consequently, future statewide modelling efforts must evaluate the effects of organic amendments on plant productivity and formation of persistent soil carbon while subtracting out apparent soil carbon gains that are driven by redistribution of biomass.

Feedstock supply may limit soil organic carbon management strategies that involve exogenous carbon inputs. COMET implements the compost-addition by assuming that 20% of the nitrogen applied as inorganic fertilizer under conventional management is replaced with compost-derived nitrogen. California's total demand for nitrogen fertilizer was 0.56 million metric tons in 2018 [56], implying a demand of 0.1 million metric tons of organic nitrogen if the practice were applied to 90% of lands receiving nitrogen. This demand might in theory be met through some combination of the nitrogen available in the sum total of California's technically available green waste (2.6 million metric tons green waste availability in 2045, [57]), particularly if supplemented with anaerobic digestate from manure [29]. This calculation suggests that emissions reductions associated with compost addition are possible from a feedstock-supply standpoint.

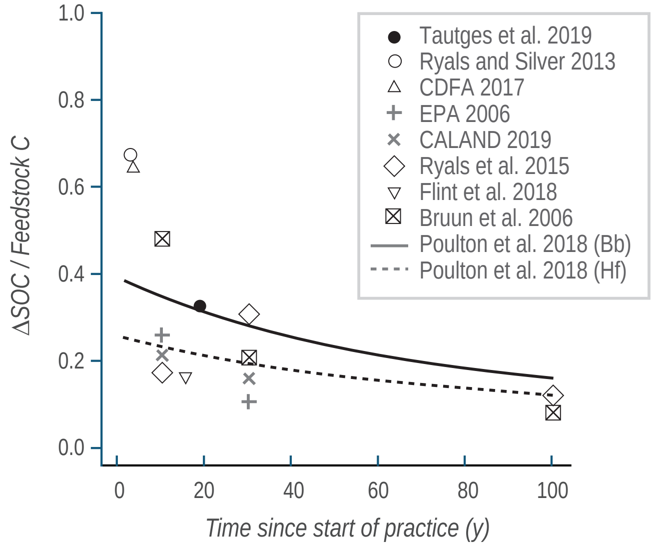


Figure 9. Change in Feedstock Yield Over Time during Compost Addition. *Studies include model simulations (Bruun et al., 2006; CDFA, 2017; Flint et al., 2018; Ryals et al., 2015); field-based mass balance calculations (Ryals & Silver, 2013); and results from direct quantification of SOC changes from long-term field studies (Poulton et al., 2018; Tautges et al., 2019). Both single-addition and continuous addition scenarios are included on the plot. Lines show statistical fits to 120-160 year long time series of SOC changes from the Hoosfield (Hf) and Broadbalk (Bd) experiments at Rothamstead in Britain. Values from outside California are shown in gray.*

Marginal Abatement Costs

The net costs of the practices considered here are challenging to estimate because costs may be offset by crop yield increases that are dependent on soil type and environmental conditions. Nonetheless, we developed initial cost estimates using dollar values summarized previously for warm/dry climates [58]. Marginal abatement costs for conservation practices 327–345 were assigned by multiplying estimates of cost per hectare provided by Smith et al. [58], by the total area applied and then dividing by the total emissions reductions obtained from COMET; compost addition scenarios were directly assigned a cost of $10 per ton of CO_2 equivalent per hectare per year as area-normalized estimates were not provided Smith et al., [58]. The value for restoring grasslands was obtained using the cost per hectare associated with set-aside and land use conversion ($10 per hectare per year); conservation rotation and cover cropping were assigned costs associated with "agronomy" as defined by Smith et al., which includes shifts in crop rotation ($20 per hectare per year); reduced tillage was assigned costs associated with tillage and residue management (5$ per hectare per year) [58]. We estimated the total marginal abatement cost for implementing all practices at $15 per ton CO_2. This cost estimate represents a first-order, global estimate for instituting these practices in warm/dry climates and is thus likely an underestimate in the context of California.

Biochar

Biochar is a condensed aromatic carbon rich substance that can be produced at a large scale from biomass pyrolysis technology. Biochar can be used as either an energy product or a soil amendment. Biochar can be combusted to provide heat for large industrial plants such as in cement production. 40% of the total emissions of 2 billion tons of CO_2 of cement industry in 2014 are from fossil fuel combustion [59].

Researchers have also investigated potential advantages when applying biochar into soil such as increasing soil carbon content, improving water retention, reducing nutrients leaching and soil bulk density [60]. However, the impacts of biochar in soil is a complex interaction among soil properties, biochar characteristics, weather, and agricultural management. More research is necessary to demonstrate long-term benefits. In this study, we only focus on the negative emissions potential from biochar application to soil.

The carbon content of biochar could vary significantly among feedstocks and pyrolysis operation conditions [61]. There is also debate about the precise duration of biochar carbon stored underground. In this report, we assume biochar from different biomass pyrolysis to be the same as 51% on a weight basis, and that 80% of the biochar carbon can be stored underground for more than 100 years [62].

Table 6. *Initial estimate of marginal abatement cost for soil carbon management practices.*

Conservation practice	Marginal abatement cost ($/t$CO_2$ equivalent)
Restore San Joaquin Valley grasslands	$ 51
Conservation rotation	$ 32
Cover cropping	$ 35
Reduced tillage	$ 30
Compost application	$ 10
All (weighted average)	$ 15

Soils and Biochar Conclusion

We estimate the near-term (2045) potential for carbon sequestration in California soils to be 3.9 million tons of CO_2 per year, but the uncertainty surrounding this value is quite large. Projecting carbon gains in response to different management practices is challenging due to the lack of California-specific long-term experimental data evaluated at the soil-profile scale. Modelled sequestration rates can provide a temporary substitute for experimental data, but the fundamental assumptions behind biogeochemical models are uncertain and may systematically influence estimates of soil organic carbon accumulation.

All emissions reduction rates from soil organic carbon management can be expected to decline over time because soils are open systems—carbon added in the past is constantly emitted, and only a small fraction of added carbon is retained in the soil at multi-decadal to millennial timescales [53]. The rates summarized here are assumed to represent a 10-year average rate [38]; beyond this timescale, soil organic carbon accumulation rates can be expected to decline. Increasing soil organic carbon in California should be viewed as a short-term strategy to achieve negative emissions that requires an ongoing commitment to soil carbon management.

Natural Solutions Conclusion

In summary, we estimate that the State could achieve 21.6 million tons of CO_2 equivalent per year of negative emissions in 2045 using the suite of natural solutions in forests, wetlands and grasslands analyzed by Cameron et al., excluding compost amendments (which we estimate separately). We also estimate, using our own analysis, that 3.9 million tons of CO_2 equivalent per year could be stored in California's soils by 2045. This yields a total of **25.5 million tons of CO_2 per year of negative emissions potential by 2045.** We calculate the weighted average cost for these negative emissions at **$11.4 per ton of CO_2** equivalent. This low number is heavily influenced by the large relative contribution of changes to forest management, which are inexpensive to implement.

CHAPTER 3

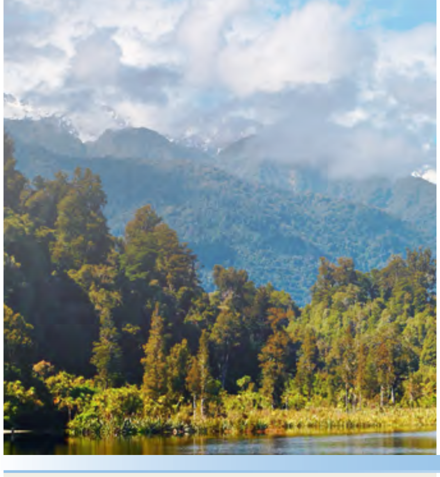
Waste Biomass Conversion: Feedstocks

SUMMARY

Waste biomass conversion with permanent CO_2 storage is the second of three pillars in our approach to negative emissions. Waste biomass is widely available across California. Today, most of the carbon from this biomass returns to the atmosphere as CO_2 or methane as the biomass decays, burns, or is used to produce energy at a power plant that vents its CO_2 emissions. This chapter outlines sources and collection costs of waste biomass in California that we considered in this report, county by county, including agricultural residue, the biogenic portion of municipal solid waste (trash), gaseous waste like that from sewage digesters, and forest waste from logging and fire prevention activities.

We use previously published work to examine the main classes of feedstock, their spatial distribution, and their current and projected availability. We describe the prevailing fate of each feedstock and its carbon under today's usage, and how much of that material could be used or repurposed for negative emissions processes. We limit our estimates to feedstocks available as a result of existing processes, practices, or policies. We intentionally do not consider new energy crops due to concerns about land use change and their energy, water and other needs.

Many biomass resources are already collected (defined as gathering, packing, and moving to the roadside), eliminating any additional collection costs for negative emissions purposes. Collection of forest biomass, on the other hand, does have associated costs but serves a double purpose, as the complex task of improving the resilience and vitality of California's forests and reducing the frequency and size of its wildfires already necessitates this forest management.



Scope of Chapter

Using existing publications and model results, we estimate the available quantities and cost of collection for the following classes of waste biomass:

- Agriculture Residue
- Municipal Solid Waste
- Gaseous Waste (e.g. landfills, manure management)
- Forest Biomass
- Beverage fermentation
- Fuel ethanol fermentation

Key Findings

We estimate the total quantity of waste biomass available in 2045 is 56 million tons per year. A summary of quantities and collection costs is shown below.

Table CS-3. *Quantities and collection cost of waste biomass available in California in 2045. BDT is bone dry metric ton.*

Biomass type	Quantity (million BDT/yr)	Collection Cost ($/BDT)
Agricultural Residue	12.7	60
Municipal Solid Waste	13	0
Gaseous Waste	6.1	0
Forest Biomass	24	0—76 (by type)

Introduction

This chapter describes the sources and quantities of waste biomass in California that can be used in biomass conversion processes, allowing the production of fuels and CO_2 streams suitable for geologic storage. These conversion processes are described in Chapter 4. Our estimates are limited to feedstocks that are available as a result of existing practices and policies, or that constitute wastes or residues of existing processes. We have only considered sources that could supply approximately 1 million tons of CO_2 per year or more, in order to keep the task manageable. We have also only considered resources that could practically be used by negative emission technologies. We intentionally excluded any new, purpose-grown energy crops from consideration due to concerns regarding direct and indirect land use change from the cultivation of these crops, as well as other impacts such as increased water and fertilizer use. We believe these filters add a degree of conservatism to our estimates.

Thus, the principal sources of biogenic carbon feedstock in California we considered are:

- Agriculture residue;
- Municipal solid waste;
- Gaseous waste from landfills and anaerobic digesters; and
- Waste forest biomass (calculated as the sum of sawmill residue, shrub & chaparral and residue from forest management)

Numerous publications have illustrated the diversity and long-term abundance of California's biomass inventory. We utilized this past work in order to determine the available biomass in California for the years 2025 and 2045. Past publications have estimated biomass availability on two bases, generally: gross and technical. An estimate of the maximum amount of biomass physically available without factoring in logistical, economic, environmental, ecological or other limitations to its sourcing is commonly referred to as a gross estimate. Such estimates are useful in analyses that attempt to show the maximum availability. Sometimes gross estimates are scaled down to reflect limitations to collection feasibility, logistical challenges and market competition. An estimate that considers these constraints is commonly referred to as a technical estimate.

Determining appropriate scaling factors that accurately and realistically reflect current and future constraints is challenging, as these factors are subject to market dynamics, site-specific variability and site-specific economics. We used a combination of gross and technical biomass category estimates. Table 7 outlines the constraints we applied to each feedstock category estimate.

In the cases where a natural ecosystem or landscape would be affected from biomass sourcing, we have imposed a variety of environmental, economic and logistical constraints on our estimates to remain conservative and realistic—notably for the forest biomass subcategories shrub & chaparral and forest management. In the cases where the biomass is available from systems created by and managed by humans, such as agriculture residue, municipal solid waste and forest biomass subcategory sawmill residue, we chose to use gross estimates under the assumption that use of the feedstocks for negative emissions is preferable to current use.

We believe that the constraints we have applied and the estimation method we have utilized adjust for outdated

Table 7. *Description of Constraints Applied to Biomass Feedstock Estimates.*

Biomass Category	Constraints Applied	Basis for Estimate
Agriculture Residue	None (Gross)	All projected collected biomass from agricultural production
Municipal Solid Waste	None (Gross)	All projected collected biomass from municipal solid waste systems
Gaseous Waste	None (Gross)	All achievable biogas recovery
Forest Biomass: Sawmill Residue	None (Gross)	All current waste from sawmill activities
Forest Biomass: Shrub & Chaparral	Logistical (Technical)	Only the technical biomass potential per Williams et al. (2015)
Forest Biomass: Forest Management	Logistical, Environmental, Economic (Technical)	Modeling applies constraints based on logistics, environmental safe-guards, and economics
Wine and Beer Starch; Energy Crops	Economic (Technical)	Achievable CO_2 recovery at pricing-district-level based on productivity

information and reflect what is possible under concerted policy action by the state, but without overreaching, being unrealistic, or ignoring undesirable side effects.

Biogenic Carbon Feedstocks Overview

In total, we estimate the total biomass availability in California for the year 2025 and 2045 to be 54 million tons per year and 56 million tons per year[1], respectively, as shown Table 8 and Figure 10. Based on the amount of carbon contained in these feedstocks, which is on average 49% by mass on a dry basis, we estimate that the amount of available biomass is equivalent to 96 million tons of CO_2 in 2025, or 100 million tons of CO_2 in 2045.[2] In the following sections of this chapter, we present details on how we estimated biomass availability for each category and subcategory. Our detailed analysis includes the geographic location for biomass by county [Appendix B].

Figure 11 illustrates the spatial distribution of the estimated biomass availability for the year 2045. The majority of the forest biomass is available in Northern California. Central California and Southern California, on the other hand, present a sizeable opportunity in terms of agriculture residues and municipal solid waste, respectively. Appendix B Table S 1- Table S 4 gives the individual values by county for all feedstocks.

California's biomass inventory is expected to increase between the years 2025 and 2045 by approximately 2 million tons per year due to changes in population and climate. California's population is expected to grow by 11% between 2025 and 2045 [63]. As a result of this population growth there would be an increase in food demand and as a result food growth will increase. As a result of climate change, changes are occurring to harvesting start, end and peak harvest duration which affects the amount of crops produced and the corresponding agricultural residues produced [57]. Another reason for the predicted increase in agriculture residue is changes in land management practices, such as replacing manual harvesting with harvesting by machines, planting several crops on the same land throughout the year or adjusting irrigation and fertilizer methods [57]. Also, as a result of population growth there will likely be an increase in the generation of waste, reflected in the increase in municipal solid waste between 2025 and 2045.

Table 8. *Summary of California Biomass Availability in 2025 and 2045. Agricultural residue and municipal solid waste are projected to increase based upon population growth. Landfill gas is projected to decrease due to SB 1383 which mandates diversion of organic waste from landfills.*

Category	2025 Amount	2045 Amount
Agriculture Residue	10.4 M BDT/yr	12.7 M BDT/yr
Municipal Solid Waste	12.3 M BDT/yr	13 M BDT/yr
Landfill and Anaerobic Digester Gas (Gaseous Waste)	7.1 M tons/yr	6.1 M tons/yr
Forest Biomass	24 M BDT/yr	24 M BDT/yr
Total	**54 M tons/yr**	**56 M tons/yr**

BDT = bone dry metric tons

In the following sections we take a closer look at the various biomass feedstock categories.

Agriculture Residue

Agricultural lands in California produce a significant amount of biomass residue material. These residues are often left on cultivated land to decompose. These residues are also used as feed additives, animal bedding, anti-erosion measures, to improve soil structure, increase the organic matter content in the soil, reduce evaporation, and to generate electricity. In all these cases, the residues release the majority of their carbon content back to the atmosphere.

Breunig et al. (2018) compiled a biomass inventory for agricultural residues for the year 2014, with predictions for 2050, which formed the basis for our agricultural residue numbers. Their analysis used geographic and temporal data from various sources, including publications, databases, and industry surveys, to characterize agricultural biomass residues by crop type for the year 2014 at the county- and month-scales. They then developed supply scenarios that reflect anticipated changes in key environmental, market, population and policy drives in order to project the biomass residues availability and location for the year 2050 [57].

Breunig et al.'s (2018) analysis included 25 sub-categories of agriculture residue, of which we only used the following: orchard & vineyard residue, field residues, row residues, row culls, almond hulls and shells, walnut shells, rice hulls and cotton gin trash. These categories were included because they make up the majority (89%) of agriculture residue that is available in California.

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[1] We use two different units for feedstock in this report. Bone dry metric tons (BDT) applies to solid material. We use metric tons (of gas) for gaseous waste, based on the volume of biogas available and accounting for the CO_2 and CH_4 composition of the biogas feedstock. For total aggregated values of both bone dry metric tons and metric tons the units are simply referred to as tons.

[2] Equivalent CO_2 = available biomass × percent carbon × molar mass of CO_2 ÷ molar mass of carbon

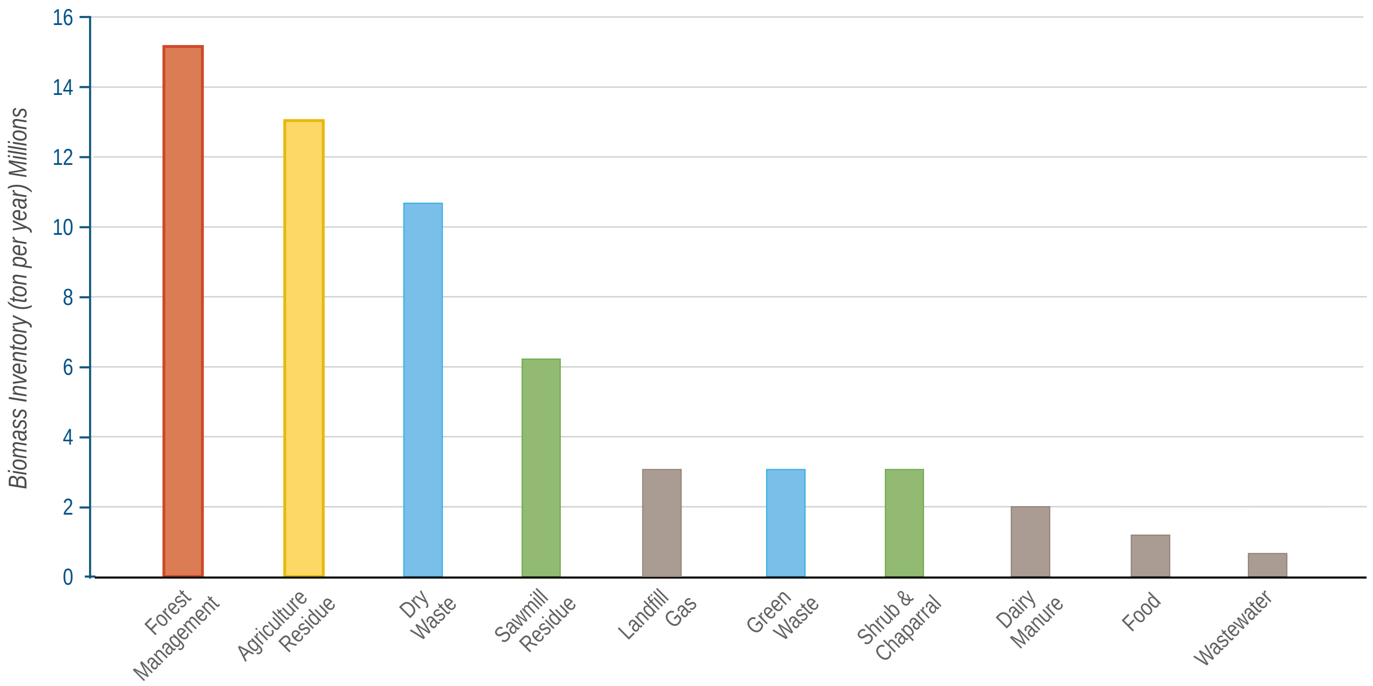

Figure 10. *Breakdown of California Biomass Feedstock Estimates for 2045 by subcategory. Quantities in bone dry metric tons per year, or metric tons of gas per year. Metric tons of gaseous waste are based on the volume of biogas available and accounting for the* CO_2 *and* CH_4 *(methane) composition of the biogas feedstock. The blue bars make up the Municipal Solid Waste category, the green bars and the red bar corresponds to Forest Biomass, while the gray bars make up the Gaseous Waste category.*

Residues are the above-ground fraction of the plant that remains once the marketable product is harvested. Part of this biomass may remain on the field to ensure soil health. Another part of it can be collected during harvest for other use. Residues are also parts of the plant that are shed by the plant or removed to improve the health and yield of the plant [57].

Culls are material left in the field because of inefficiencies in harvesting, if produce is rejected for not meeting market standards, or in the case of orchards if there is stress on the tree and fruit are dropped before, they are ready to be harvested. Production of culls and residues from row crops will occur during harvest while residue production from orchard & vineyards will occur with winter pruning, spring and summer trimming and tree removal. Field residue will also be generated during harvest [57].

Row residues and row culls are considered high-moisture residue, whereas orchard & vineyard residue, field residues, almond hulls and shells, walnut shells, rice hulls, and cotton gin trash represent low-moisture residues. The moisture content affects which conversion technologies are appropriate for utilization. This will be discussed and analyzed further in Chapter 4.

We used a linear interpolation to estimate available quantities for 2025 and 2045 from Breunig et al.'s data [57]. The total agriculture residue availability is projected at approximately 10.4 and 12.7 million bone dry tons (BDT) per year, for the years 2025 and 2045 respectively. The sub-categories that make up this agriculture residue availability are shown in Table 9 and by county in the Appendix B, Table S 1.

There is substantial growth in the available agricultural residue between the years 2025 and 2045. Breunig et al. predict growth in agricultural residue of approximately 2.3 million bone dry tons between 2025 and 2045.

The majority of agricultural residue in 2045 is projected to be in Northern California (10.3 million bone dry tons per year), with 2.3 million bone dry tons per year in Southern California.

Municipal Solid Waste

In order to estimate the biogenic municipal solid waste (MSW) inventory for 2050, Breunig et al. used two scenarios: a business-as-usual case that extends recent disposal and recycling trends, and a more aggressive recycling scenario that meets existing and proposed recycling legislation and goals as of 2018 [57]. For these two scenarios, the disposal rate was modified according to the population change estimate published by the California Department of Finance in order to project the municipal solid waste availability for 2050 [57]. In this report, we use the more aggressive recycling scenario given the high likelihood in the continuation of the trend to expand recycling efforts throughout California.

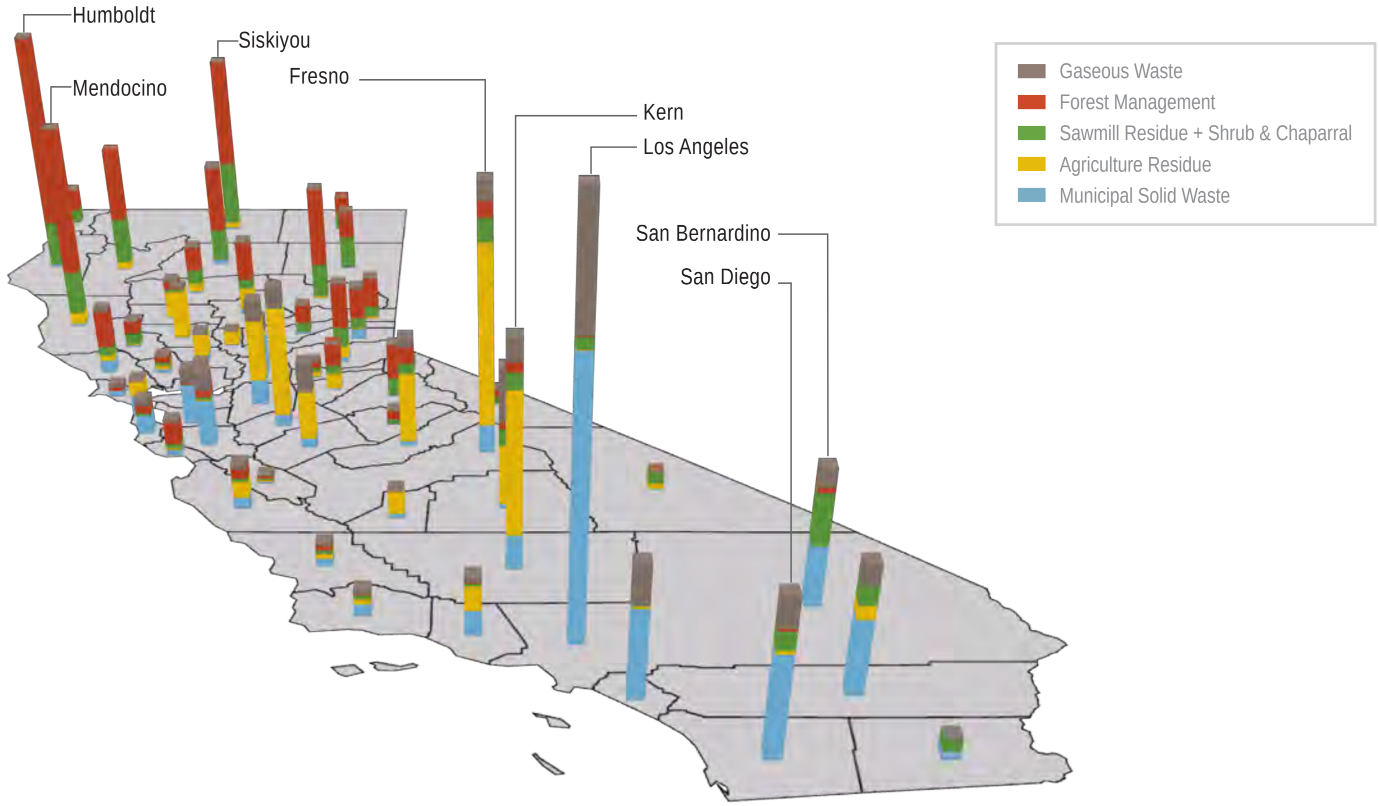

Figure 11. *Spatial Distribution of Biomass Resources in California for the year 2045. Los Angeles total biomass availability 3.4 million tons*

Breunig et al. divide biogenic MSW into seven sub-categories [57]. We only consider sub-categories of over 500,000 bone dry tons (BDT) per year: green, lumber, wastepaper, cardboard and "other". The moisture content of each category determines whether the waste would be processed via thermal methods (low-moisture solids) or via anaerobic digestion (high-moisture solids). Green waste is considered high-moisture municipal solid waste, whereas lumber, paper, cardboard, and other are considered low-moisture municipal solid waste. Food was not included in the municipal solid waste totals because it was assumed that food waste would be processed using anaerobic digestion. As such, food waste is covered under our gaseous waste estimates.

As with agriculture residue, we used a linear interpolation to estimate available quantities for 2025 and 2045. The total municipal solid waste projected to be available in the years 2025 and 2045 is 12.3 and 13 million bone dry tons per year (Table 10). The municipal solid waste feedstock quantity availability is presented by county in the Appendix B, Table S 2.

The majority of municipal solid waste biomass in 2045 is projected to be in Southern California (8.2 million bone dry tons per year), with 4.8 million bone dry tons per year in Northern California.

Gaseous Waste from Landfills and Anaerobic Digesters

Biogas that is rich in methane and carbon dioxide is spontaneously generated from the decomposition of biogenic

Table 9. *California Agriculture Residue Biomass Availability Estimates for 2025 and 2045.*

Sub-Category	2025 Amount (BDT/yr)	2045 Amount (BDT/yr)
Orchard & Vineyard Residue griculture Residue	3,600,000	3,800,000
Field Residue	1,800,000	2,000,000
Row Residue	325,000	340,000
Row Culls	350,000	565,000
Almond Hulls	2,900,000	4,200,000
Almond Shells	695,000	990,000
Walnut Shells	290,000	360,000
Rice Hulls	310,000	310,000
Cotton Gin Trash	150,000	180,000
Total	10,400,000	12,700,000

BDT = bone dry metric tons

Table 10. *California Municipal Solid Waste Biomass Availability for 2025 and 2045.*

Municipal Solid Waste Sub-Category	2025 Amount (BDT/yr)	2045 Amount (BDT/yr)
Green	2,500,000	2,600,000
Lumber	3,300,000	4,200,000
Paper	3,200,000	2,600,000
Cardboard	880,000	1,000,000
Other	2,300,000	2,500,000
Total	12,300,000	13,000,000

BDT = bone dry metric tons

Table 11. *California Gaseous Waste Biomass Inventory in 2025 and 2045.*

Feedstock Source	Resource 2025	Resource 2045
Wastewater	1.1 x 10^{12} gallons/year	1.2 x 10^{12} gallons/year
Dairy Manure	1.5 million dairy cows	1.7 million dairy cows
Landfills	143 facilities with 6.2 x 106 tons	143 facilities with 4.14 x 106 tons
Food Waste	1.2 million bone dry tons	1.5 million bone dry tons

waste, for instance in landfills during the decomposition of deposited matter. Anaerobic digesters also liberate biogas from food waste, municipal wastewater, and dairy manure. Table 11 summarizes the estimated total size of each of these feedstocks in 2025 and 2045. Biogas compositions and projected production rates in 2025 and 2045 are inventoried in Table 12. A more detailed analysis of each of these categories follows. Because these gaseous wastes are currently released to the atmosphere if not controlled, managing them is essential to reducing existing emissions as well as creating negative emissions.

Landfill Biogas

For many decades, California's municipal landfills have been accumulating organic food, yard waste and non-organic waste that is not recycled. Anaerobic microbes digest this organic waste, liberating several gases, primarily methane and CO_2, which are present in approximately equal amounts. The gases also include small amounts of nitrogen, oxygen, and hydrogen, as well as several hazardous or otherwise undesirable compounds. This biogas that is released from landfills accounts for ~20% of the methane emissions in California, as well as a substantial amount of CO_2, and is therefore both a significant greenhouse gas liability and a bioenergy resource. Processing biogas for energy also generates CO_2, which can be captured and geologically stored.

Landfill biogas collection costs are very low, as the gas spontaneously flows through pipes, as many as several hundred, sunk into the field. The gas that enters each line is drawn to a central processing plant under low vacuum [64]. Thus, landfills are more economical sources of methane, and potentially CO_2, than dairy manure or other waste streams that require more energy and capital and operating expenditures to capture the biogas. Energy from landfill gas therefore requires lower incentives to generate.

Table 12. *Inventory of California biogas sources used in this report.*

Source	Biogas Production Step	Biogas Composition	2025		2045	
			billion ft^3/yr	million tons/yr	billion ft^3/yr	million tons/yr
Wastewater	Anaerobic Digestion	65% CH_4 35% CO_2	12	0.4	13	0.4
Dairy Manure	Anaerobic Digestion	60% CH_4 40% CO_2	50	1.7	56	1.9
Food Waste	Anaerobic Digestion	60% CH_4 40% CO_2	25	0.9	28	1.0
Landfill Gas	None	50% CH_4 50% CO_2	109	6.2	73	4.1

Wastewater treatment plants will also produce bio-solids at 560,000 and 610,000 bone dry tons of solid waste in 2025 and 2045, respectively. We did not find a conversion factor to estimate the biosolids remaining from anaerobic digestion of food and manure waste. ft^3 = cubic feet, CH_4 = methane

The EPA's Landfill Methane Outreach Program database listed 298 landfills in California in February of 2019. Of these, 143 report having biogas collection systems in place. Current EPA regulations require that owners/operators of landfills above a certain permitted size (2.5 megatons of waste) collect and combust the landfill gas, either by flaring or using it to generate energy [65]. The landfill sites in California that do not have a collection system in-place either report low levels of solid waste in place or are designated by the EPA "low potential", or both. We excluded these sites from our analysis.

Currently, based on 2019 EPA Landfill Methane Outreach Program data, California landfills generate 126.7 billion cubic feet of biogas per year [65]. Parker et al. (2017) estimated that the 147 most productive landfills in California in 2016 produced methane at a rate of 57 billion cubic feet per year. As methane typically accounts for ~50% of the volume of landfill gas that number amounts to 114 billion cubic feet of biogas, which is comparable to our estimate [66].

In projecting the landfill contribution to negative emissions potential, we took into account that SB 1383[3] requires a 75% decrease in organic waste deposits to landfills by 2025 (compared to 2014 levels) [67]. Landfills closed to new waste nevertheless continue to release biogas at a rate that decreases by 2–5% per year [66]. Therefore, there will be no more than 109 billion cubic feet of biogas in 2025 and 73 billion cubic feet of biogas available in 2045.

These calculations are based on an estimated 2% annual decrease in biogas generation at any site [66].

Eighty-five of California's landfills use biogas to generate electricity and send it to the grid. Eighty-six report flaring of biogas. Twenty-eight of those that report flaring also either generate electricity or renewable natural gas. Nine are direct combined heat and power users. Seven generate renewable natural gas.

Production of renewable natural gas requires separation of the methane and CO_2 in relatively pure states but electricity production is commonly carried out by burning the relatively impure biogas (following siloxane removal and dehydration) as fuel for an internal combustion engine (generator) [65]. The resulting engine exhaust CO_2 could be used for carbon capture and storage, but we did not consider post-combustion capture from biogas combustion due to lack of available data on small-scale post-combustion capture costs. We did not assess CO_2 capture from flared biogas because this pathway lacks any source of revenue, in addition to lack of available data on small-scale post-combustion capture costs.

Biogas from Wastewater Treatment Plants

California wastewater is currently collected and treated at approximately 250 treatment plants distributed across the state [68]. The majority – greater than 90% – of the approximately 1 trillion gallons of wastewater processed in California every year is processed by anaerobic digestion at 153 facilities yielding biogas that is approximately 65% methane and 35% CO_2, and biosolids. The primary current use of biogas at wastewater plants is for electricity generation through biogas combustion, where the combustion product CO_2 is not captured and sequestered.

Both biogas and biosolids could be utilized to achieve negative emissions if the CO_2 portion or the CO_2 resulting from methane combustion is captured and sequestered, which is not currently done. Because the collection of biogases and biosolids is already routine practice as part of wastewater management, we do not consider any cost of production of biogas or biosolids from wastewater. However, in Chapter 4, we consider the additional costs of biogas upgrading for pipeline injection and other pathways that can yield negative emissions. In order to project wastewater volumes in 2025 and 2045, we assumed a population growth rate of 0.6% per year and that wastewater volumes will increase proportionally [57]. To convert wastewater flow rate to biogas flow rate, we used a conversion factor of 1.15 cubic feet of biogas per 100 gallons of water [64].

We estimated the biosolids remaining after anaerobic digestion to be 187 bone dry metric tons per year per million gallons per day [57]. In 2025, the estimated amount of biogas and biosolid products available from anaerobic digestion at wastewater treatment plants is 12 billion cubic feet, and 560,000 bone dry tons, respectively. The total amount of CO_2 available from the biogas (assuming all available carbon is converted to CO_2 through combustion) is 875,000 tons per year. We assumed that the biosolids contain 30% carbon and therefore could contribute 616,000 tons of CO_2 per year [68]. In 2045, biogas and biosolids carbon are projected to increase to 14 billion cubic feet (950,000 tons CO_2) and 610,000 bone dry tons (671,000 tons CO_2) per year, respectively [57]. Due to the lower relative quantity of CO_2 available from biosolids than biogas, and other processing, contamination, and transport logistical issues, we did not further consider biosolids as a source of CO_2 for this report.

Biogas from Food Waste

In order to help achieve the goals of SB 1383 to reduce 75% of organic waste deposited in landfills by 2025, municipal solid food waste could be processed either in commercial

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[3] Lara, Chapter 395, Statutes of 2016.

composting facilities or by existing anaerobic digesters at wastewater treatment plants. For this report, we assumed that food waste would be diverted to digesters at wastewater treatment plants to generate biogas for two reasons. First, because there is likely sufficient extra capacity at wastewater treatment plants and second because anaerobic digestion of food waste enables the ability to capture and store atmospheric CO_2 from biomass with greater certainty than composting, and this report is focused on that removal of CO_2. We determined the available biogas based on the bone dry tons of food waste reported by Breunig et al. (2018) and interpolated to 2025 and 2045 [57]. We assumed 0.84 g total solid per g of volatile solid and that 0.29 g volatile solid produces 1 g of methane. From these data, we estimate that in 2025, 1.3 million bone dry tons will produce 14 billion cubic feet of biogas, and in 2045, 1.5 million bone dry tons will produce 16 billion cubic feet of biogas. The biogas produced from food waste has an estimated composition of 60% methane and 40% CO_2 [69] .

Biogas from Dairy Manure

Agricultural emissions account for 8% of California's greenhouse gas emissions, and manure and enteric sources account for 60% of agricultural emissions [70]. Cow manure is a biogenic source of carbon that can be harvested as biogas via anaerobic digestion. The methane can used for energy and the CO_2 sequestered to achieve negative emissions.

Currently, there are 1,331 dairies in California, primarily concentrated in the San Joaquin Valley. There are 30 operational anaerobic digesters in these dairies, with 123 in development [71], [72]. Due to the high methane emissions from dairies, SB 1383 requires a 40% reduction in methane emissions from dairy manure management relative to 2013 by 2030. In this report we assume that by 2025 most dairies will have anaerobic digesters installed. However, if the economics of fuel production and CO_2 storage increased the amount of methane reduction beyond 40%, this would reduce California's residual emissions and accordingly reduce the amount of negative emissions required to reach carbon neutrality. Currently, 60% of existing diaries store manure in lagoons that can be inexpensively upgraded to covered-lagoon anaerobic digestors [73].

For the purposes of this biogas inventory, we calculate the gross resource: biogas production based on the assumption that all dairy manure in the state will be anaerobically digested. In Chapter 4 we add additional constraints on this biomass based on economies of scale for biogas upgrading. County level manure levels are calculated based on cattle populations provided by the Central Valley Regional Water Quality Control Board and Santa Ana Regional Water Quality Control Board. Data compiled by Rob Williams at University of California, Davis indicate that dairy biogas is currently produced at 85.5 cubic feet per day per animal [73]. Based on predicted human population growth and linear extrapolation of per capita dairy product consumption, by 2045 manure production will have increased by 21% [57]. We do not include manure that is infeasible to collect, such as manure from pasture grazed animals.

Table 12 shows the volumes, compositions, and processing steps for the four biogas sources discussed above. The gaseous waste feedstock quantity availability is presented by county in the Appendix B Table S 3.

Forest Biomass

Mixed-conifer forests are extensive throughout California providing carbon storage, recreation, timber, watershed protection, wildlife and fish, as well as wilderness. These working forests are now under increasing stress due to a rising number of large and destructive wildfires, mortality from drought, and historical and new invasive pests [74]. These threats must be addressed to improve the resilience and vitality of California's forests. This is a complex task in California forests, which fall under different ownerships with varying goals.

We consider the following major categories of forest biomass (illustrated in Figure 12):

- Sawmill residue, estimated from existing resources;
- Shrub and chaparral management, which is considered distinct from management on timberlands, given their unique ecological features; and
- Biomass residues from commercial forestry operations and treatments performed for the purpose of forest restoration, including decreasing wildfire likelihood and/or severity (Forest Management).

We explain these in more detail below.

Sawmill Residue

We use the definition of sawmill residue from Williams et al. (2015), who define it as "a byproduct of the milling of sawlogs [...] Sawmill and other forest product manufacturing operations generate a variety of wood residues including bark, sawdust, planer shavings and trim ends" [69]. They estimate total sawmill residue at 6.2 million bone dry tons per year based on 2005 timber industry data [69]. A portion of this estimate is currently being used for power generation in the state with additional amounts used for landscape and other products. It is outside the scope of our analysis to consider the economic and/or greenhouse gas changes associated with changing the existing fate of this biomass source – we merely analyze the greenhouse gas implications of processing it in ways that maximize CO_2 capture. The majority of the sawmill residue is available in Northern California (6 million bone dry metric tons per year, with a much smaller amount in Southern California (0.2 million bone dry metric tons per year). If timber operations expand in California, we expect sawmill residue supply to increase as well. However, we did not include potential supply increases in this report.

Shrub & Chaparral

Williams et al. (2015) describe shrub & chaparral as "[...] mostly shrubby evergreen plants adapted to the semi-arid desert regions of California, especially in the south state" [69]. They state that despite extending over a large area, shrublands remain largely untapped for their biomass and have little current commercial value. As such, they estimate the available resource only as a result of "habitat improvement activities (such as thinning) or fuel treatment operations designed to reduce wildfire risks" [69]. We include shrub & chaparral here as a separate resource because it is managed very differently to timberland. These values must be considered imprecise and extremely dependent on land-use policy.

Most of this material is logistically available as result of most of the resource being located in areas with easy access. However, some the material is in areas of steep slopes that render this material inaccessible. Our shrub & chaparral biomass availability estimate aims to exclude such material by using the technical potential estimate from Williams et al. (2015).

The total shrub & chaparral that is estimated to be available is 2.6 million bone dry tons per year [69]. Williams et al. estimate shrub & chaparral at 1.5 million bone dry tons per year in Southern California, and 1.1 million bone dry tons per year in Northern California.

Forest Management

California timberlands are now under increasing stress due to a rising number of large and destructive wildfires, mortality from drought, and historical and new invasive pests [74].

Fuel treatments have been shown to effectively mitigate fire behavior and effects in wildfires [75], thus playing an important role in adaptation to a changing climate. Based on this, California has signed into law SB 901[4] which requires the state to double forest fuel removal. California's Forest Carbon Plan, prepared by a consortium of state agencis and stakeholders, contemplates an increase in mechanical fuels treatment to firmly establish California's forests as a more resilient and reliable long-term carbon sink [76].

CalFire and the United States Forest Service have begun implementation of a variety of fire-prevention treatments—including both mechanical thinning as well as controlled burns—to eventually reach an aspirational goal of treating 1 million acres of land annually, in order to reduce the likelihood and severity of wildfires [76]. This represents a significant increase from the current rate of treatment. As a first step towards ramping up to the million-acre annual goal, CalFire has identified 35 high-priority projects mostly in the urban-wildland interface, which amount to approximately 90,000 acres [77].

A substantial amount of forest biomass that can be used in negative emission pathways may be generated as a result of managing 1 million acres annually. In order to estimate that amount, we relied on the work of Dr. Daniel Sanchez and Bodie Cabiyo at the University of California, Berkeley. The goal of managing 1 million acres per year will either require large amounts of dedicated funding, or more profitable approaches to fuel reduction treatment. For this reason, Sanchez and Cabiyo use an economically-driven model to identify the least cost-intensive forest management that could contribute to the Forest Carbon Plan goal.

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[4] Dodd, Chapter 626, Statutes of 2018.

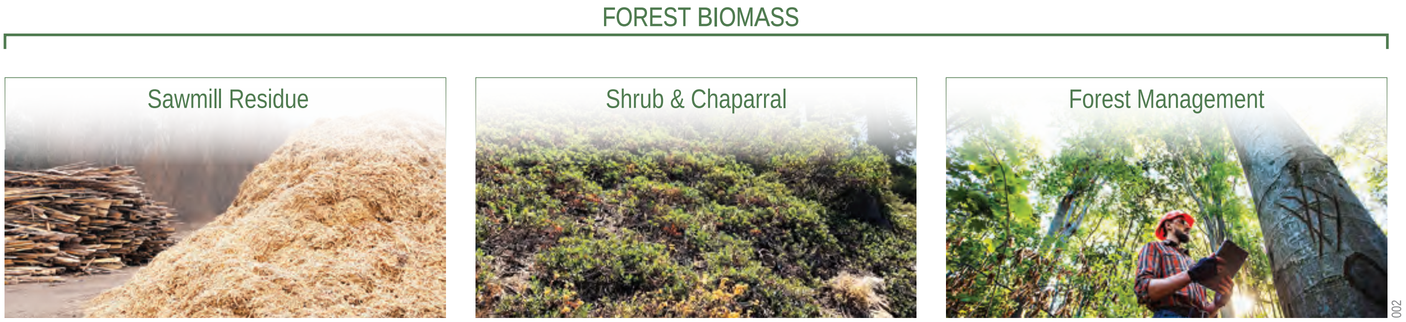

Figure 12. *Forest Biomass Sub-Categories considered in this report.*

Sanchez and Cabiyo estimate the volume of biomass that could be thinned from California timberland under existing wood prices and best practices for fuel load reduction. Their modeling suggests that mechanical thinning could enable profitable management of up to 800,000 acres per year, substantially contributing to the state goal of treating 1 million acres per year for fire prevention.

At the core of Sanchez and Cabiyo's simulation are two tools originally developed by United States Forest Services: The Forest Vegetation Simulator and BioSum. Forest Vegetation Simulator is a growth and yield model which takes Forest Inventory and Assessment plot data as an initial condition and models changes in forest structure and composition over a set period (here, 40 years). Sanchez and Cabiyo modeled six management scenarios in Forest Vegetation Simulator to represent a range of best and current forest thinning practice on California timberland, including five uneven-aged thinning scenarios and one "grow only" scenario (see [78]).

BioSum is a forest management decision-making tool which uses economic and geospatial inputs to optimally choose Forest Vegetation Simulator management scenarios [79], [80]. To reflect decisions that may be made in alignment with the Forest Carbon Plan, management scenarios were chosen with three sequential decision criteria: (1) effective reduction in potential fire mortality using the Forest Vegetation Simulator Fire and Fuels Extension; (2) ability to generate positive net revenue (i.e., not lose money); and (3) ability to maximize in-stand carbon. Delivered biomass chip prices were set at $100 per bone dry metric ton, which offsets the additional costs of not leaving biomass in the forest (e.g., chipping and hauling to a processing facility). In addition, merchantable (sawlog) timber prices were set according to the California Board of Equalization. For this report, only biomass chips are considered in the final analysis for negative emissions use, although saw timber production is a critical, if implicit, economic driver for modeled forest management. In total, 2134 Forest Inventory Assessment plots (a total acreage of 12.3 million unique acres) met the decision criteria for management under one of the five management scenarios. The data from these plots is statistically representative of all economically available biomass from fire- and carbon-beneficial forest management on California timberland. Over a twenty-year period, management occurs at a rate of over 800,000 acres per year.

The total biomass residue from these forest management activities during a twenty-year period is 15.1 million bone dry metric tons per year. The majority of this residue is in Northern California (14.8 million bone dry metric tons per year), with a much smaller quantity available in Southern California (0.3 million bone dry metric tons per year). This biomass estimate includes both the quantity that would be directly removed by United States Forest Service and CalFire in their pursuit of fire treatment, and also related activities performed by forest landowners or commercial operators that satisfies similar objectives, consistent with the 2018 California Forest Carbon Plan. As such, thinnings or slash from commercial operations that are not fit for sawmill use are included in this estimate.

Forest Biomass Total

Based on the analysis above, we estimate the total forest biomass availability in 2045 for California, calculated as the sum of sawmill residue, shrub & chaparral and residue from forest management, at 24 million bone dry metric tons per year. This resulting biomass is only from existing management plans. It is outside the scope of this analysis to assess how the growth in the market of biomass for energy or utilization will affect forest managers and their treatment plans and therefore, the corresponding forest biomass availability.

The biomass inventory values are averaged over a 25-year period, so the same number is representative for 2025 (as for 2045). Table 13 shows forest biomass inventory broken down by category for the year 2025 and 2045. The forest biomass feedstock quantity availability is presented by county in the Appendix B, Table S4.

Wine and Beer Starch

The winemaking and brewing industries in California are another potential source of CO_2 that can be captured and sequestered. Grape juice to be fermented into wine contains nearly 25% weight/volume sugar and a typical wort to be

Table 13. *California Forest Biomass Estimates for 2025 and 2045.*

Category	2025 and 2045 Amount (BDT/yr)
Sawmill Residue	6,200,000
Shrub & Chaparral	2,600,000
Forest Management	15,100,000
Total	**24,000,000**

BDT = bone dry tons

brewed would contain approximately 8% weight/volume fermentable sugars [81]. As a result, every volume of grape juice fermented releases approximately 55 volumes of CO_2 (at ambient conditions) [81]. While beer fermentations typically release less CO_2, roughly 18 volumes per volume of beer, the brewing industry is generally a continuous process. In contrast, winemaking is seasonal with fermentations occurring during three to four months of the year.

The wine industry in California, however, is larger than the brewing industry. California is home to approximately 3,900 bonded wineries as compared to only 1,000 breweries [82]. The contributions to the national scale also show the importance of the California wine industry, which produces nearly 80% of the domestic wine, while the state's brewing industry represents only 10% of the national production. While both industries have many producers, the volume is dominated by a few very larger companies.

The size, by tons harvested for wine grapes, of two most recent vintages are 2017 and 2018. In each of these two vintages, more than 4 million tons of grapes were harvested and processed into wine [83], [84]. Approximately 0.5–0.55 tons of CO_2 would be released during fermentation if the average concentration of sugars is estimated at 25%. The locations of the facilities where the fermentations occur is not readily available publicly, but we can estimate the distribution of fermentation by the reported winegrape crop by pricing district [85]. This approach is used to determine the regional size, by tons harvested, of grapes grown and sold for wine production. The pricing districts are aggregates of counties or parts of counties across California, with the values summed to provide the size of the crop at the state level.

While craft breweries have increased the number of locations in recent years, the volume of beer produced is still dominated by a few producers and locations. For instance, in 2017, the 841 craft breweries accounted for about 15% of the beer production in California while single sites of large production facilities accounted for about 20% of the state's beer production. While some of the CO_2 evolved is used for carbonation or as a processing aid, the opportunity of capturing CO_2 from breweries is their continuous operation through the year.

Table 15. *CO_2 Released from Wine making in California.*

Year	Tons Harvested	Approx. CO2 Released (tons)
2018	4,281,684.2	535,210.5
2017	4,015,792.4	501,974.1

Although publicly available location data for characterizing wine production is limited, the overall production of CO_2 from wine, and its relative purity, is an opportunity worth pursuing. A challenge in adapting technologies to the wine industry is that production is concentrated to a few months per year and thus wineries will have more tanks per volume of beverage produced, and thus more from which to collect CO_2. Breweries provide a useful opportunity to test out CO_2 collection strategies that can then be adapted initially to small wineries and then scale to larger production facilities.

To estimate the cost of collection of CO_2 from these ethanol fermentation sources, we examined the distribution of fermentation aggregated by pricing district and the number of wine production licenses for each district to calculate the average facility size, and calculated the cost of drying and compressing the CO_2 for each facility. Only the largest wine grape pricing districts — 12, 13, and 14, located in the central valley — produce enough CO_2 to make drying and compression economically-feasible and account for approximately half of the available CO_2 from wine production. The cost to capture this CO_2 was aggregated with the cost for capturing CO_2 from energy crop fermentation (below).

Table 14. *Characteristics of Wine and Beer.*

	Wine	Beer
Source of Sugar	Fresh Grapes	Dried Grains
Concentration of Sugars	~25%	~8%
CO_2 Produced	55 v/v	18 v/v
Production Months Annually	3-4	12

Table 16. *CO_2 Produced from Beer making in California.*

	Barrels	Tons of CO2
One Large Location	4,500,000	19,166.7
California Craft Breweries	3,421,295	14,572.2
Total	20,000,000	85,185.2

CO_2 from Existing Fermentation of Existing Energy Crops

Energy crops such as corn and switchgrass can be grown for conversion into fuel ethanol via fermentation. Though this is largely done in the Midwest U.S., California produces fuel ethanol largely from four plants in the state, totaling about 200 million gallons of ethanol per year [86]. To supplement the demand for fuel ethanol, California largely imports ethanol from other states, roughly an additional 1,300 million gallons in 2015 [87]. Fermentation of sugars contained in the energy crops produces one molecule of CO_2 per molecule of ethanol, and this CO_2 is emitted from the fermenter is a nearly pure stream saturated with water, only requiring drying and compression prior to storage. Because this CO_2 does not contain contaminants that may be found in industrial sources of CO_2, it is often sold in California for use in the food and beverage industry. However, it could, in principle, be repurposed for negative emissions. In this case, CO_2 capture from existing fuel ethanol plants in California can contribute approximately 600,000 tons of CO_2 per year. If CO_2 were also captured from out-of-state fermenters supplying ethanol to California, the fuel ethanol consumed in California would contribute an additional 3.8 million tons of CO_2 per year [87], [88].

We recognize that placing a value on the biomass resources we have described, even though they are currently considered to be wastes, will increase their supply. Of concern is the extent to which energy crops might be grown to be added to the biomass resources we have tabulated, and whether this would have a material impact on agriculture in the State of California. We used the results of the DOE's Billion Ton Report to examine the magnitude of this effect [88]. The Billion Ton Report evaluates current and future biomass resources in the United States. The most recent Billion Ton Report: BT16 is the third DOE-sponsored report of this kind. It employs the Policy Analysis System to assess the economic availability and competing demands for biomass resources and simulates how commodity markets balance supply and demand through price adjustments, based on a biomass sale value [88]. The price point we chose to determine this availability of energy crops in California from the Billion Ton Report is $100 per bone dry ton. This is the highest price point that could be chosen in the Billion Ton Report and as a result will have the greatest effect on the results. In 2045[5] the Billion Ton Report forecasts that California will produce an additional approximate 650,000 bone dry tons per year of energy crops [88]. Since this amount is small, we did not make any attempt to consider the effect of additional bio-energy crops on future California supply.

Combined with CO_2 from the wine and beer industries, we estimate that these existing sources of CO_2 derived from ethanol fermentation yield a total of 0.8 million tons of negative emissions per year, with the total cost for drying, compressing, and providing temporary on-site storage of approximately $42 per ton of CO_2.

Moisture Content of Biomass

Though our analysis is performed based on bone dry tons of biomass, which is defined as biomass having 0% moisture content, it is important to acknowledge that the actual moisture content of biomass is non-zero, is different for different sources of biomass, and varies seasonally. This is important when considering appropriate treatment methods for different biomass sources (Chapter 4), the extent to which the biomass must be pre-dried, and the total "green" weight of biomass that must be considered in calculating the transportation cost of biomass (Chapter 7). The average moisture content of the various biomass sources considered in this report are listed in Table 17. Values for woody biomass moisture content were taken from NREL report TP-5100-61178 and values for all other moisture content were taken from Breunig et al., [57], [89].

Table 17. *Average Moisture Content for the Biomass Inventory Categories.*

Biomass Category	Average Moisture Content
Sawmill Residue	30%
Shrub & Chaparral	30%
Forest Management	30%
High Moisture Agriculture Residue	80%
Low Moisture Agriculture Residue	25%
Dry Municipal Solid Waste	10%
Wet Municipal Solid Waste	50%
Existing Energy Crops	25%

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[5] The Billion Ton Report projects biomass resource availability out to the year 2040. For this report it is assumed that the biomass availability in the year 2040 would be comparable in 2045.

Collection Cost of Biomass Resources

Biomass collection includes gathering and packaging; all the collection costs assumed in this report are shown in Table 18 (transportation costs are considered in Chapter 7). It varies as result of the type of biomass, sequence of collection operation, the efficiency of collection and many other factors. We did not consider sawmill residue, municipal solid waste, biosolids, manure, landfill, starch source and energy crops to have a collection cost because the collection is already underway for other reasons, and there is no additional cost gather these feedstocks for negative emissions purposes.

The collection for the biomass categories shrub & chaparral and agriculture residue were determined from the Billion Ton Report [88]. The collection cost for forest management was determined from CalFire data [77].

The Billion Ton Report outputs the varying collection costs for harvesting logging residues and whole trees for both clear-cut and thinning treatment methods. It outlines these collection costs by region—we used the inland west region costs. Williams et al., (2015) [69] estimated the amount of shrub & chaparral available but did not define a collection method, so we determined the collection cost for shrub & chaparral from the Billion Ton report harvest and cut definitions that most closely correspond to the shrub & chaparral category: “cut-to-length” systems and “full tree”. Cut-to-length systems process the trees/forestry at the stump which disperses the biomass across the site and the full tree systems bring the limbs, tops and other residue to the roadside for process [88]. The “clear cut” definition corresponds to the shrub & chaparral category. Clear cutting refers to the removal of all standing trees and woody biomass in a selected area, the entire tree including the logs, branches and tops are either left on the field or collected for further utilization [88]. We used $76 per bone dry ton, the average of cut-to-length clear cutting and full tree clear cutting costs from the Billion Ton values.

Table 18. *Collection Costs for the Biomass Inventory Categories.*

Biomass Category	Cost
Sawmill Residue	$0 (Performed by Others)
Shrub & Chaparral	$76/BDT
Forest Management	$50/BDT
High Moisture Agriculture Residue	$60/BDT
Low Moisture Agriculture Residue	$60/BDT
Municipal Solid Waste	$0 (Performed by Others)
Biosolids	$0 (Performed by Others)
Wastewater Biogas	$0 (Performed by Others)
Manure	$0 (Performed by Others)
Landfill	$0 (Performed by Others)
Starch Source	$0 (Performed by Others)
Existing Energy Crops	$0 (Performed by Others)

BDT = bone dry ton

The collection cost for forest management residue data was obtained from CalFire [77]. Currently, CalFire has begun forest treatment/fire treatment on 35 projects. The data including number of acres treated and total cost was obtained from the CalFire database [77]. We assumed that 15 bone dry ton per acre of biomass is available [90]. The average cost per bone dry ton of biomass resources was calculated for the 35 current projects. The average cost which correspond to our collection was determined to be $50/BDT for forest management residue.

We used the collection cost from the Billion Ton Report for high and low moisture agriculture residue. They use a market price of $60 per bone dry ton as the farmgate or roadside or collection cost (i.e., after harvest, cost to collect and prepare residue for delivery to a processing facility) [88]. Therefore, we use the same value ($60 per bone dry ton) as our collection cost for agriculture residue.

It is assumed that the cost of collection does not change over time. It is true that changes in how collection will occur to optimize biomass utilization and that this affects the cost. However, we are unsure what changes will occur and how those will affect the collection cost. Determining these changes and their corresponding effect on collection is outside the scope of this paper. Therefore, the assumption that the collection cost will remain constant was made.

Carbon Accounting Considerations and Definitions for Biomass

While a full carbon accounting undertaking over the entire lifecycle of the biogenic carbon feedstocks considered in this report is outside its scope, we have considered several important related factors when estimating negative emissions potential.

Lifecycle Considerations for Biomass

A fundamental consideration when relying on the use of biomass to realize negative emissions is the overall carbon balance of the process. This is typically addressed through attributional lifecycle assessment. One important consideration in the outcome of such attributional lifecycle assessments is the **counterfactual,** which is an assumption of what would occur otherwise in place of the action under question—in our case, the implementation of the negative emissions pathway(s). Counterfactuals are often vigorously contested, especially in the context of forest biomass.

Trees are living carbon sinks, and larger trees generally store more carbon annually than smaller ones. Physical considerations, for example whether forest land is converted to another use, whether a felled tree is replaced by another, and the foregone sequestration that takes place for a certain time period if a small tree replaces a larger one, are fundamental to the overall carbon balance.

Several other counterfactual considerations also need to be considered, commonly discussed under the topic of indirect land use change. If economic drivers, laws, regulations, policies or practices make a quantity of biomass firmly available for a negative emissions process, then if the carbon from that biomass is stored permanently, we count it as negative emissions. This would be the case, for example, for residue from a particular type of agricultural practice that is taking place today, which is burned in the field due to lack of other disposal means. A counterexample could be the deliberate conversion of non-agricultural land to cultivate crops for specific use in negative emissions pathways. Claiming the full carbon benefit in the latter case would be wrong, and we have excluded such types of biomass feedstock from our consideration.

It may even be the case that avoided emissions can also be realized alongside negative emissions if, for example, it is statistically established that a certain acreage of forest biomass would have burned in wildfires, releasing its carbon. We do not attempt to evaluate these complicated scenarios in this report. No avoided emissions are included for biomass when calculating our base negative emissions. We do calculate avoided fossil emissions only when a biofuel could replace that fossil fuel, as described in Chapter 4.

In preparing this report we attempted to take a conservative approach to these life cycle considerations, without directly calculating them. Table 19 is a summary of the likely impacts of instituting a negative-emissions approach for the biomass feedstocks that we consider in this report. A more detailed future evaluation of these effects will be necessary to fully understand the net carbon balance of the negative emissions technologies we discuss, but we hope that our conservative approach in each case would result in the net climate benefit being greater than what we currently calculate. Our approach for each biomass class is described in the following sections.

Table 19. *Summary of Counterfactuals for the Waste Biomass Feedstocks.*

Feedstock	Assumed Business as Usual (Counterfactual)[6]	Are there Avoided Emissions Resulting from Implementation of Negative Emissions Process?
Agriculture Residue	Decomposition, electricity generation, fuel, soil amendment, animal feed, controlled/open burning	Possibly
High-Moisture Municipal Solid Waste	Decomposition	Possibly
Low-Moisture Municipal Solid Waste	Decomposition, recycling	Possibly
Biogas from Dairies	Venting, flaring, electricity generation, fuel	Yes
Biogas from Landfills	Venting, flaring, electricity generation, fuel	Possibly
Biogas from Wastewater Treatment Plants	Venting, flaring, electricity generation, fuel	Possibly
Forest Biomass: Sawmill Residue	Decomposition, electricity generation, fuel, fiber/particle board	Possibly
Forest Biomass: Shrub & Chaparral	Wildfire, decomposition, controlled/open burning	Yes
Forest Biomass: Forest Management	Wildfire, decomposition, controlled/open burning, natural changes to stored carbon	Possibly

Agriculture Residue

The estimates of agriculture residue by Breunig et al., (2018) [57] rely on projected changes in key environmental,

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[6] Note that one or more of the stated business-as-usual fates are possible – we are not implying that all of them will necessary take place, even though that is possible in some cases.

market and policy drives in order to project the biomass residues availability and location for the year 2050. However, this is not premised on any additional cultivation or land use conversion to agriculture with the specific purpose of increasing agriculture residue availability (for use in negative emissions applications, or otherwise). Any future land use changes are driven by population growth and demand for food. As a result, we believe their assessment does not present a conflict between the potential for utilization of agriculture residues in the amounts assumed in this report and the preservation of lands that are currently not being used for agriculture, and that counting the embedded carbon as negative is valid.

In terms of avoided emissions, the variety of residues involved makes for an uncertain assessment. It is possible that some residues will be used as soil amendments for land that will remain untilled, but we consider tilling the more likely fate. The majority of the total would likely be left to decompose, be pile-burned, or used as fuel, thereby re-releasing its carbon to the atmosphere.

Municipal Solid Waste

The fates for low- and high-moisture municipal solid waste may be different today. For example, paper and cardboard (low moisture) may be diverted from landfills to be recycled, or may eventually decompose as compost. High-moisture waste (e.g. food waste) would either be landfilled or composted. In addition, SB 1383 also aims to reduce the amount of food waste that reaches landfills. Therefore, it may not be valid to factor in avoided emission for the entirety of the municipal solid waste resource we have estimated, but we cannot currently estimate the effect of recycling efforts in 2045. In either case, removal of carbon from either type of waste using the processes considered in this report would constitute a negative emission.

Biogas from Dairies, Landfills and Wastewater Treatment Plants

Today, few dairies capture the methane they generate, but landfills and wastewater treatment plants routinely do. For wastewater, more than 90% of the processed wastewater volume is already treated using existing anaerobic digestion facilities in California [68]. However, the usual fate for the captured biogas is for it to be flared (to CO_2), used to generate electricity or as a gaseous fuel. The remainder that is not captured, is vented. For dairies and landfills (and food waste, discussed in Chapter 3), SB 1383 requires 40% reduction in methane emissions relative to 2013 levels by 2030.

It may not, therefore, be valid to assume that the entirety of the biogas from dairies, landfills and wastewater treatment plants will result in avoided emissions—only the portion that isn't being captured today and used as a substitute for fossil fuels. However, we see no factors that call into question counting the embedded carbon as negative in a negative emissions pathway. We do not take any negative emissions credit for reducing the amount of emitted methane because we consider that to be an emission reduction.

Forest Biomass: Sawmill Residue

The possible fates for sawmill residue absent any new negative emissions uses are for it to be left to decompose in situ, be used as a soil amendment in working soils where tilling will likely result in the re-release of the carbon, be used as a fuel to generate electricity or heating fuel, or be used in solid products such as fiber or particle board. Of these, only the solid products may already be resulting in negative emissions, but the lifetime of these products is uncertain, and their fate may be that of delayed decomposition.

Given that we do not assume any expansion of sawmill residue availability for the purpose of, or as a result of realizing negative emissions in our estimates, we consider it valid to count the embedded carbon as negative. For the fates that would result in emissions (decomposition), also counting an avoided emission would be valid. Some of the fates may already be realizing an avoided emission, such as the use of sawmill residue as a substitute for fossil fuels in electricity or heat generation.

Forest Biomass: Shrub & Chaparral

The premise behind the shrub & chaparral estimates that we use is that only quantities that are necessary for fire prevention, and as genuine residues of preventative treatments, are sourced for negative emissions. By this definition, the fate of this biomass would have been to eventually combust in wildfires or prescribed burns, or to decay as a forest residue, since hardwood species found in shrub and chaparral ecosystems do not typically have large merchantable value in California markets. Therefore, we consider it valid to count the embedded carbon as negative. To the extent that this management practice results in avoiding the combustion of the remaining, untreated shrub and chaparral ecosystem, avoided emissions may also be possible.

Forest Biomass: Forest Management

The state has signaled very strongly through the 2018 Forest Carbon Plan and the actions of CalFire (and United States Forest Service) that treatment of the 1 million acres per year – which drives our forest management biomass availability estimates—is a high priority. Mechanical thinning – the removal of some trees at fixed spacing intervals will be used to some extent, but is not an option everywhere, for example on steep slopes or wilderness areas. Controlled burns will also have to be utilized.

Because the residues generated from mechanical thinning do not typically have a significant value in California markets, their expected fate is to decay in the forest and release their carbon to the atmosphere over time. Prescribed burns/controlled burns, by definition, lead to the release of the carbon embedded in the biomass during combustion. It is possible that, as a consequence of increased demand for residues, more forest management would occur additionally to the Forest Carbon Plan goal. However, the modelling framework used here suggests that biomass availability is fundamentally limited by accessibility and state regulations like the Sierra Nevada Forest Plan. The model results suggest that market forces are highly unlikely to drive forest thinning over 1 million acres per year.

Because we consider this biomass availability to be a direct byproduct of the USFS' and CalFire's stated forest management goals, we do not include a full biogenic accounting of forest carbon here. The full counterfactual of removed forest residue would require modelling fire frequency and severity, biomass decomposition and competition-induced mortality among other factors, which are outside the scope of this report. Sanchez and Cabiyo's modelling also includes the generation of some merchantable wood (saw logs) which requires a more complex set of counterfactual considerations, but those outcomes are not included in our biomass estimates.

Forthcoming results from Sanchez and Cabiyo that do include these factors suggest that the carbon benefit associated with the treatment processes highlighted here outweigh losses from management. Further information about this modeling framework will be presented in detail by Sanchez and Cabiyo, to be published in early 2020.

Treatment of Avoided Emissions

The optimal calculation for attributing avoided emissions to a specific bioenergy pathway would consider the extent to which fossil emissions would be avoided today or will be mandated to be avoided in the future should the pathway be implemented. We choose to not venture into any such assumptions in this report—which would be highly subjective in our view—but instead to simply present the maximum avoided emissions that could be claimed for a particular negative emissions pathway.

We also choose to not make any assumptions about the likelihood and severity of wildfire and any emissions that would result. We do not count avoided wildfire emissions in our estimates, even though we do rely on biomass that is removed for wildfire prevention purposes to achieve negative emissions.

Biomass Resource Conclusion

California has diverse and massive biomass residue-based resources. The biomass inventory of 54 million tons per year and 56 million tons per year in 2025 and 2045 respectively identified in this chapter reflects logistical, environmental and economic constraints. We believe that the constraints we have applied and the estimation method we have utilized adjust for outdated information and reflect what is possible under concerted policy action by the state, but without overreaching, being unrealistic, or ignoring undesirable side effects. The majority of the forest biomass is in Northern California, agriculture residue is concentrated in Central California, and the largest amounts of municipal solid waste are from Southern California, giving a remarkably uniform biomass supply across the state.

Our results are lower than some recent assessments. Williams at al. (2015) estimated a total gross availability of 78 million tons of biomass, and a technical (practical) availability of 35 million tons. We weighed the specific constraints associated with sourcing each biomass type for negative emissions purposes and used a combination of gross and technical estimates. Our assessment yielded a value (56 million tons), which lies between their two values. We also recognize that placing value on these resources could significantly increase their supply, but we have not attempted to quantify that effect.

As a result of the abundant waste biomass resources available in California there is the opportunity to capture and chemically or geologically sequester approximately 96 million tons of CO_2 per year in 2025 or 100 million tons of CO_2 per year in 2045, based solely on the amount of carbon contained in the biomass resources. This number represents the amount of CO_2 that could be sequestered if all of the carbon in the biomass were converted to CO_2, and all of that CO_2 were captured and sequestered. In reality, the amount of CO_2 that can be sequestered will be lower than this number (see

Chapter 4), due to the inability to economically capture 100% of the CO_2, and the likely synthesis of some carbon-containing products (e.g. liquid transportation fuels with some carbon content through biomass pyrolysis vs. carbon-free hydrogen synthesis through gasification).

In the next chapter, we evaluate the technical feasibility of capturing CO_2 from these biomass sources using different biomass conversion technologies and evaluate a range of technology and product scenarios in terms of their negative emissions potential and cost to capture CO_2.

Table 20. *Summary of California Biomass Availability Inventory for 2025 and 2045.*

Category	2025 Amount	2045 Amount
Agriculture Residue	10.4 M BDT/yr	12.7 M BDT/yr
Municipal Solid Waste	12.3 M BDT/yr	13 M BDT/yr
Landfill and Anaerobic Digester Gas (Gaseous Waste)	7.1 M tons/yr	6.1 M tons/yr
Forest Biomass	24 M BDT/yr	24 M BDT/yr
Total	54 M tons/yr	56 M tons/yr

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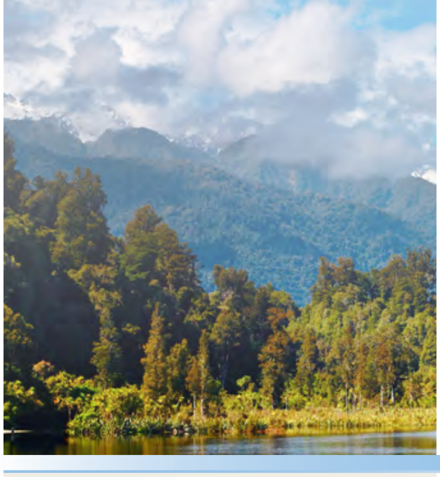
CHAPTER 4

Waste Biomass Conversion: Biomass Treatment Processes



SUMMARY

California's extensive and varied waste biomass resources could yield approximately 100 million tons of negative emissions per year in 2045 if all the carbon were converted to CO_2, captured, and stored. This chapter estimates the amount and cost of the CO_2 recoverable for negative emissions for economically practical processes to make fuels and products. These biomass conversion technologies enable the second, and largest, of the three pillars of the negative emissions system.

Approaches for biomass conversion include torrefaction, pyrolysis, gasification, anaerobic digestion, and hydrothermal liquefaction. These technologies can produce, variously, long-lived carbon products, liquid fuels, gaseous fuels (hydrogen, renewable natural gas), electricity, or combinations. All of these options create CO_2 at the time of conversion, which can be captured and stored permanently for negative emissions. The produced fuels can also be used for carbon-neutral energy, replacing fossil fuels to avoid existing emissions, as well as providing a revenue stream to reduce the cost of negative emissions. We estimate the amount of recoverable CO_2 and costs of all of these approaches, using available literature and a discounted cash flow rate of return method without assuming any regulation or subsidy. The biomass feedstocks considered include everything covered in Chapter 3: forest biomass, agricultural residue, municipal solid waste, and gaseous waste.

Scope of Chapter

Analysis and comparison of technologies that convert biomass to products while generating negative emissions. We compare the following on the basis of cost per ton of CO_2 removed and total quantity of CO_2 removed for various types of biomass supplies in California:

- Gasification
- Fast Pyrolysis
- Hydrothermal Liquefaction
- Biogas Utilization

KEY FINDINGS

Biomass conversion technologies that generate the most recoverable CO_2 from biomass provide the greatest climate impact. Conversion of biomass to hydrogen or electricity using gasification or combustion (bioenergy with carbon capture and storage-BECCS) generates the most recoverable CO_2, since nearly all of the carbon in the biomass can be captured during processing. Of these technologies, we found that the maximum negative emissions potential, 83 million tons per year, and lowest cost per ton CO_2 can be achieved through gasification of the solid biomass types to produce hydrogen. If the replacement of residual fossil fuels is a priority, then producing liquid fuels using pyrolysis is practical, but in general removes less CO_2 and leaves the state with more of a shortfall to reach the 125 million ton goal. This is because more of the carbon in the biomass remains in fuel and returns to the atmosphere. We also found that collection and processing of biogas could provide up to 7 million tons of negative emissions per year when processed and sent to a central power plant equipped with CO_2 capture.

Introduction

California has abundant waste biomass resources which could result in a maximum of approximately 100 million tons of negative emissions per year in 2045 if all of the carbon in the biomass were converted to CO_2, captured, and permanently stored. While biomass combustion with carbon capture and storage, “BECCS, ” is a straightforward route for converting biomass carbon to electricity and CO_2 suitable for geologic storage, other technologies exist today which can convert biomass into useful chemicals, fuels and co-products, such as syngas, hydrogen, renewable natural gas (RNG), and bio-oil while also producing CO_2 for geologic storage. These products can provide a revenue stream, reducing overall costs of capturing CO_2. In addition, bio-derived chemical/fuel/energy products can displace/replace fossil derived fuel and energy, reducing residual emissions. In some cases, the production of a bioproduct or bioproduct intermediate may also improve the economics of transporting biomass.

The purpose of Chapter 4 is to compare biomass conversion technologies for a given feedstock on the basis of cost per ton of CO_2 and amount of CO_2 recoverable from that feedstock, (the negative emissions potential, in millions of tons per year). Sales of fuels or other co-products, using the equivalent fossil-derived price, are included as part of the calculation to reduce the cost of CO_2 capture. These costs are intended to inform decision making about which biomass conversion technologies and products to consider for further analysis, which will include biomass and CO_2 transportation logistics, in Chapter 7. The cradle-to-grave boundaries of the analyses in Chapter 4 are dependent on each process scenario and are represented by process flow diagrams within each technology sub-section.

We considered two main categories of CO_2 available from a source of biomass, as illustrated in Figure 13: Process CO_2 is the CO_2 that is generated during the process of converting biomass to fuels and chemicals, such as the CO_2 generated during anaerobic digestion or fermentation. Process CO_2 is some fraction of the total carbon available in the biomass. The fuels produced may be combusted to produce electricity; in this case, if the CO_2 is captured, it is counted as part of the process CO_2. If the fuels are to be used for transportation, and thus the emissions are not captured, that CO_2 is emitted to the atmosphere as Combustion CO_2.

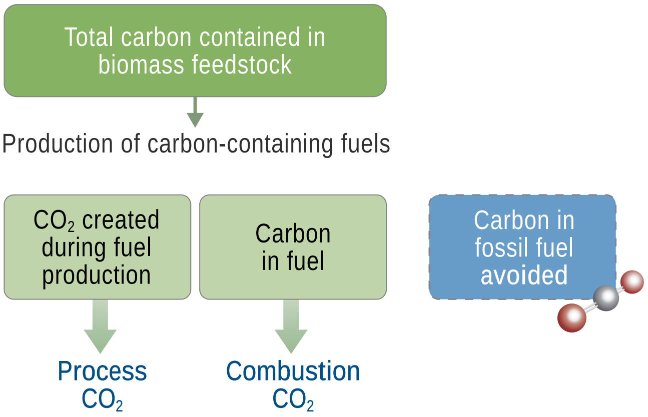


Figure 13. Illustration of categories of CO_2 from biomass conversion technologies. *Process CO_2: created during biomass processing; Process + Combustion should roughly equal the amount of CO_2 contained in the biomass. Avoided: CO_2 emissions avoided due to using a biomass-derived fuel rather than fossil-derived fuel.*

Additionally, but separately, we will also account for the emissions of CO_2 that were avoided because fossil fuels and chemicals were displaced with biomass-derived fuels and chemicals. Note that we did not explicitly account for changes in avoided emissions due to alternative uses or fates of the biomass such as those listed in Table 19. The only avoided emissions that are counted are those attributable to displaced fossil-based fuels and chemicals.

The biomass conversion technologies highlighted in this report are not intended to represent an exhaustive list of all the possible biomass conversion technologies in development today. We selected technologies and product pathways that were all at least at pilot scale and, in most cases, were tied to large scale demonstrations; process cost estimates at realistic scales, either from academic literature, industry, or reports, could be obtained. Figure 14 shows the scale of commercial plants for the technologies considered in this report. In general, the facility sizes we considered in this report are larger than those currently deployed commercially. However, for technologies like gasification and combustion, which have many facilities at a range of scales, the technology is relatively mature. This indicates that no major technological breakthroughs are necessary to leverage biomass conversion for negative emissions generation, just deployment at scale. For fast pyrolysis, which is less mature than gasification and combustion, we consider the effect of large-scale deployment on the cost of the technology over time in Chapter 8 on technology learning.

We matched available biomass feedstocks to technologies according to the suitability of the biomass, based on cellulose and moisture content, as illustrated in Figure 15. For example, we deemed low (<30%) moisture, highly cellulosic feedstocks such as agricultural residue to be more suitable for gasification and pyrolysis, and high moisture (>50%) lower cellulose content feedstocks such as manure and wastewater biosolids to be more suitable for anaerobic digestion. Of course, with additional pre-processing and cost, any of the

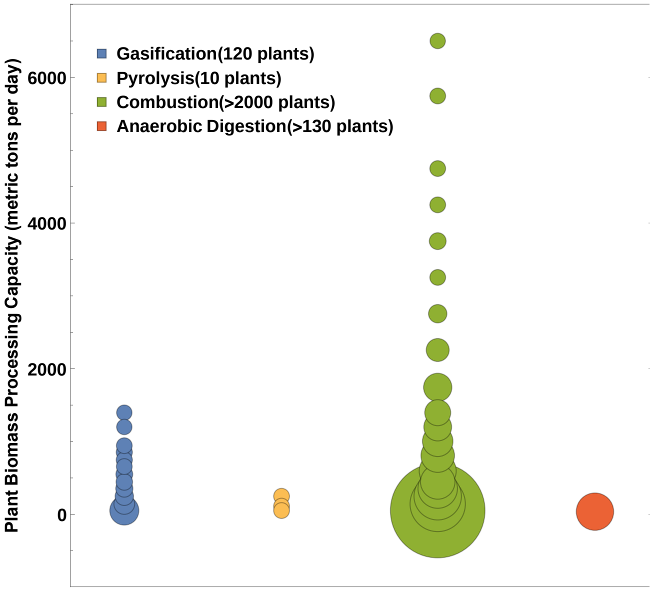


Figure 14. Range of existing commercial facility sizes for biomass conversion technologies considered. *Facilities smaller than 10 tons of biomass per day were not considered commercial scale for the purposes of this figure. The size of the dot indicates the relative number of facilities at a given scale of biomass processing capacity. The largest biomass combustion facility, Drax, located in the United Kingdom, combusts 20,000 tons of biomass per day and is not shown on the figure.*

feedstocks, with the exception of landfill gas, could be made suitable for any of the technologies. In general, we chose the most straightforward routes with minimal pre-processing steps to match biomass feedstocks to biomass conversion technologies. Additionally, we assessed the overall cost and negative emissions potential of producing different products using a given technology. For simplicity, we accounted only for wholesale (non-incentivized) product prices as revenues in our analysis.

The product scenarios have a large impact on process economics and the amount of process CO_2 available for geologic storage, summarized in the product scenarios column of Figure 15. Our analysis incorporates a carbon balance calculation for each feedstock to product pathway, as well as a technoeconomic assessment of the cost per ton of CO_2 removal for each product pathway. The costs of 1) biomass collection 2) biomass conversion technology, 3) CO_2 capture, drying, compression, and onsite storage are included for each pathway in Chapter 4. Additionally, we included certain product transport costs, such as biogas pipeline, since renewable natural gas pipeline significantly impacts the capital investment. For liquid fuels and hydrogen, we used plant gate prices that do not include product transportation. Comparisons of technologies on these criteria based upon 2045 feedstock projections are shown at the end of Chapter 4.

We calculated incremental costs to produce negative CO_2

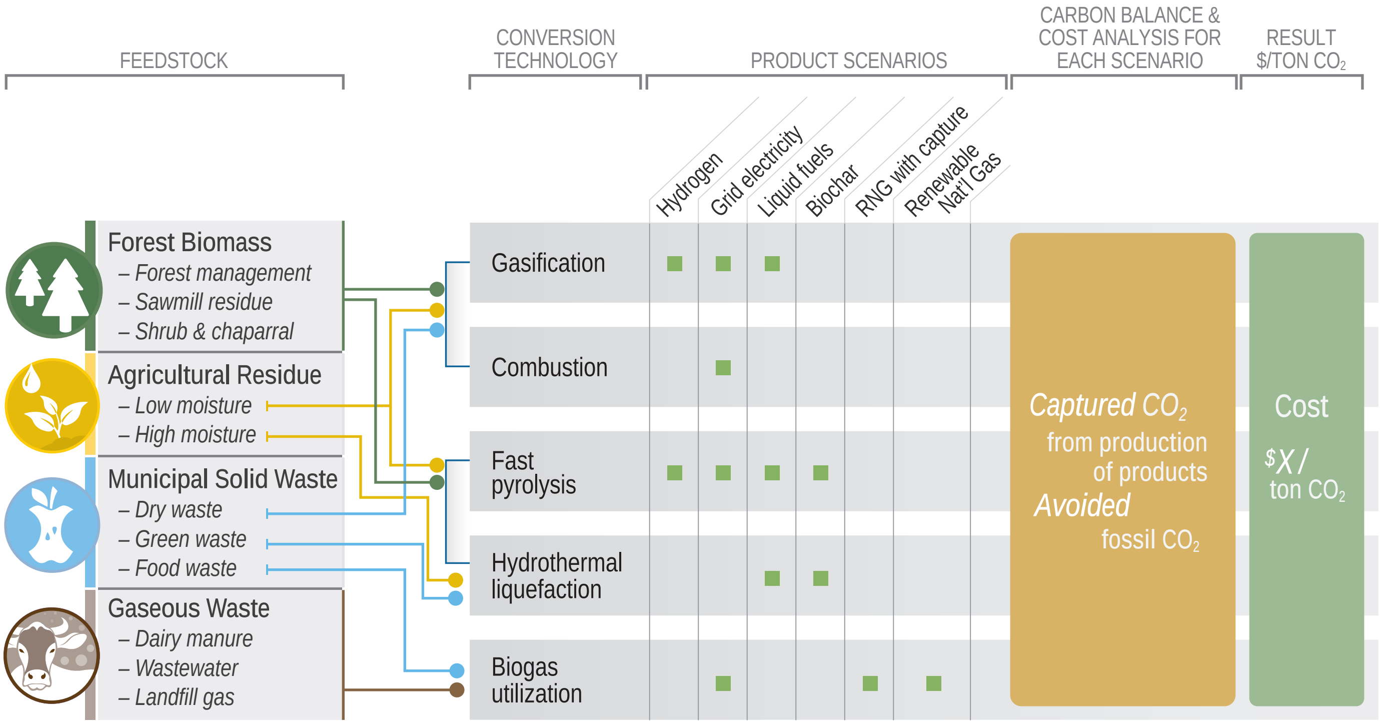


Figure 15. Diagram linking biomass type to conversion technology. *From left to right, the biomass feedstocks associated with conversion technologies considered for the different feedstocks, products considered from each technology, and emissions scenarios evaluated.*

Equation 2. *Negative Emissions Carbon Cost Formula.*

$$\text{Negative Emissions Carbon Cost} = \frac{\text{Product Cost of Negative Emissions Technology} - \text{Current Product Wholesale Price}}{CO_2 \text{ emissions from Negative Emissions Technology}}$$

emissions from all potential negative emissions technologies in dollars per ton CO_2 equivalents, as shown in Equation 2 and Figure 16. Details of the calculations can be found in Appendix D. In most cases, our negative emissions are purely CO_2; in scenarios that produce biochar, we assume that 80% of the carbon remains in the soil for 100 years and calculate the CO_2 equivalents based on that.

Capital and operating costs are included for the full system; we defined capital costs as the total expenditure to purchase and install all system equipment. In order to estimate the negative emissions potential, we added CO_2 capture & compression systems on different biomass conversion technology processes from literature. We calculated the CO_2 capture, drying and compression capital costs by scaling similar configurations demonstrated elsewhere [91]. The scale up factors are gathered from quality guidelines produced by National Energy Technology Laboratory research group [92]. Additional capital equipment, such as a hydrogen liquefaction train [93], [94], was also added as necessary depending on the base configuration of the process from literature.

We scaled capital cost based on literature reports and estimated as an annualized repayment over the twenty-year plant life and an internal rate of return of 10%, leading to an overall annual capital charge factor of 15%. We calculated variable operating costs based on the mass and energy balance of the system and the costs of biomass collection in Table 18. We additionally assumed a fixed operating cost at 4.5% of the capital investment [91]. These factors sum to the "Product Cost of Negative Emission Technology" shown in Equation 2. This value is then discounted by the current (reference) product wholesale price for each pathway, shown in Table 21, to determine the yearly net cost after revenue.

We counted the carbon flow and estimated the negative CO_2 equivalent emissions potentials for different pathways based on their mass and energy balances. Finally, the yearly net cost after revenue is divided by the annual amount of CO_2 captured to calculate the cost to capture CO_2 (Equation 2 and Figure 16). All costs are calculated and reported on a 2018-dollar value basis, scaled using the Chemical Engineering Plant Cost Index.

To calculate the annual negative emissions potential for a given pathway, we multiplied the amount of negative emissions per ton biomass by the annual feedstock production. To estimate the avoided fossil emissions associated with the various scenarios, we chose emissions reference cases for different pathways based on the major products from each pathway, [95] which are shown in Table 21. As noted above, we did not attempt to account for or quantify any avoided emissions due to alternate fates for the biomass. The only avoided emissions are due to displaced fossil-derived chemicals and fuels.

We represent the cost to capture CO_2 and negative emissions potential across feedstocks and technologies in Figure 30-Figure 33. When costs vary within a feedstock category (e.g., due to multiple feedstock collection costs or sizes of facility), the average cost to capture CO_2, weighted by the

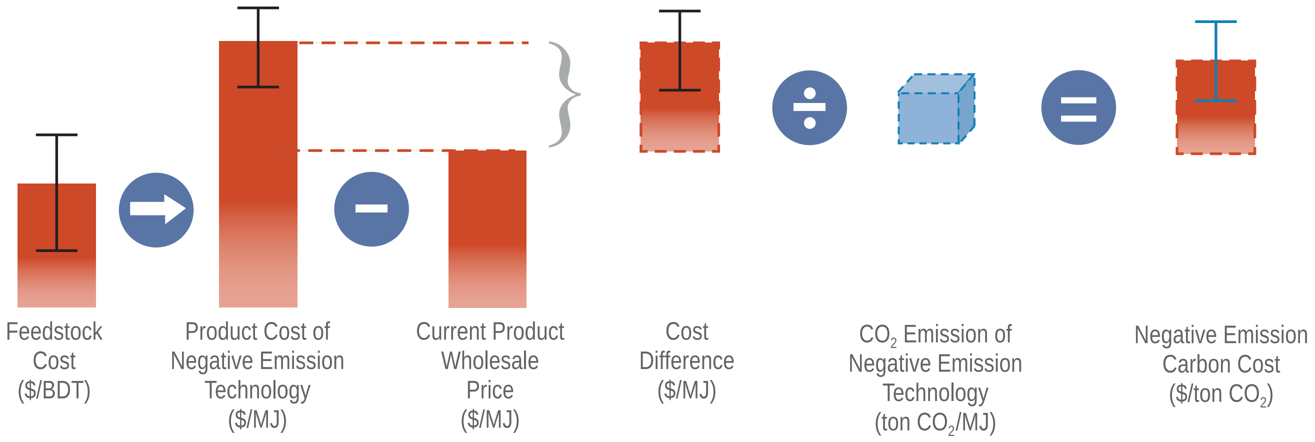


Figure 16. *Overview of accounting in negative emissions cost calculations.*

Table 21. *Current (Reference) Product Wholesale Prices and Greenhouse Gas Emissions. (Data sources: [CA-GREET Model], [DOE Hydrogen and Fuel Cells Program], [Simbeck et al. 2002], [EIA Daily Prices], [EIA Electricity Data], [EIA Natural Gas Citygate Price in California])*

	Current Product Wholesale Price	Reference Product Greenhouse Gas Emissions
Liquid Fuels	\$2.35/GGE	101 g CO_2/MJ
Compressed Hydrogen	\$2.00/kg	126 g CO_2/MJ
Liquid Hydrogen	\$2.90/kg	126 g CO_2/MJ
Natural Gas	\$4.16/tcf	81 g CO_2/MJ
Electricity	\$0.06/kWh	170 g CO_2/MJ

GGE = gallon of gasoline equivalent, tcf = thousand cubic feet, kWh = kilowatt hour, MJ = megajoule

negative emissions potential, is shown as the major bar and the range of cost values is shown as error bars in Figure 30 – Figure 33. Sensitivities of total cost to variations of biomass costs and base product prices are shown at the end of this chapter in Figure 34 – Figure 37.

Our cost analysis in this chapter does not include CO_2 or biomass transport, which will be covered in Chapter 7. However, if less than 1,000 tons of CO_2 is produced per day, we assume that the CO_2 will need to be stored onsite prior to transportation by truck; as shown in the process flow diagrams, we incorporated the cost of process CO_2 onsite storage. For onsite CO_2 storage, we assumed each facility would have a cryogenic CO_2 storage tank with 30 ton CO_2 capacity with the installation cost of \$1,120,000 [96].

Gasification

Gasification is a process that converts a solid or liquid fuel into a mixture of gases (mostly carbon monoxide, hydrogen, and CO_2) at high temperature and pressure. This mixture of gases, known as synthesis gas or syngas, can then be converted into other useful products or burned in a combined cycle to produce heat and power. Originally, gasification was developed to use coal as the fuel, but increasingly there has been interest in using the technology to process biomass and waste. When integrated with CO_2 capture and sequestration, use of biomass gasification enables carbon-negative fuel or power production.

Gasification technologies vary by how the fuel comes in contact with the gasifying agent. There are many reviews on this topic, and so we do not discuss the applicability of different configurations here. Generally, for the size of gasification plant considered here (>100 megawatts input biomass), a pressurized fluidized bed gasifier or entrained flow gasifier, such as those developed and commercialized by Gas Technology Institute, is most suitable [97].

There are four processes that occur in a gasifier: 1) feedstock drying, 2) devolatilization to produce char, 3) combustion to provide the heat, and 4) gasification reactions. Overall, these processes are endothermic, and so heat must be provided to drive them. In particular, the gasification reactions are strongly endothermic, and so gasification is typically performed between 700 and 1200° C to drive the reactions to completion.

In principle, the heat for gasification can be provided by an external source (allothermal gasification). However, by introducing an amount of oxygen directly into the gasifier that is less than what is needed for complete combustion of the fuel, the heat required for the gasification process can be provided by partial combustion of the fuel. This is termed autothermal gasification. All of the processes considered in this analysis use oxygen-blown autothermal gasification to provide the heat necessary for complete gasification of the biomass. As opposed to air-blown, oxygen-blown gasification requires the addition of an air separation unit but has the benefit of reducing the size of downstream equipment and making gas separations less energy intensive, due to the elimination of diluent nitrogen.

After the biomass has been gasified, the resulting gas must be cleaned up prior to its use in downstream processes. This includes cracking of tars that are produced and removal of any particles that form from the inorganic ash content of the biomass, which is typically several percent of the dry mass. The resulting impure gas is called producer gas and is

GASIFICATION OVERVIEW

- Inputs: forest biomass, low moisture agricultural residue, dry municipal solid waste
- Potential products: liquid fuels, hydrogen, electricity
- Key points: relatively mature individual technology components benefit from economies of scale leading to large facilities that capture CO_2 at low cost
- Could capture between 58 and 76 million tons of CO_2 per year at \$14–92 per ton CO_2 depending on biomass source and end product

composed of predominantly hydrogen, CO, CO_2, water, with small amounts of sulfur-, nitrogen-, and chlorine-containing compounds. Depending on the downstream processes, these contaminant compounds may need to be removed if they can damage equipment or catalysts. The cleaned syngas can then be passed to downstream process equipment.

Compared to coal, biomass contains much lower amounts of these contaminant elements, making gas cleanup easier. However, biomass contains significantly more oxygen than coal, and so the energy content of biomass per unit mass is lower. In general, biomass with low moisture content, like woody residues and almond shells, is preferred to high moisture biomass, like row crops or food waste, because the first stage of gasification is drying. The higher the moisture content of the biomass, the more of the biomass must be combusted to dry the remainder of the biomass, and so the yield of fuels or power will be lower. Therefore, in this analysis, the sources of biomass that we consider applicable for gasification are the forest biomass sources forest management , sawmill residue, shrub & chaparral), the dry agricultural residues (orchard & vineyard residue, field residue, almond hulls and shells, walnut shells, rice hulls, and cotton gin trash), and dry municipal solid waste (lumber, paper, cardboard, other), as defined in Chapter 3.

The pathways we considered for processing this biomass are detailed below. For the gasification pathways, the preparation of feedstock and gasification are common units, but processes downstream of the gasifier are dependent on the final product being made.

Scenario 1: Gasification with Fischer-Tropsch Synthesis to Liquid Fuels

Formation of liquid alkane fuels (gasoline and diesel) from syngas occurs via Fischer-Tropsch synthesis. The general process components are relatively mature, making this a technology option that is often considered; Fischer-Tropsch synthesis is performed commercially for syngas derived from coal and natural gas at many sites internationally. The largest Fischer-Tropsch installation is the Secunda coal-to-liquids facility in South Africa, owned and operated by Sasol, producing about 160,000 barrels of liquid alkane fuels per day [98].

Despite the commercial success of this technology, there are still some drawbacks to producing liquid fuels from biomass in this way. The Fischer-Tropsch catalysts are sensitive to sulfur and nitrogen-based compounds, which are present in the raw producer gas. Though biomass has less sulfur and nitrogen than coal, the syngas that is sent to the Fischer-Tropsch

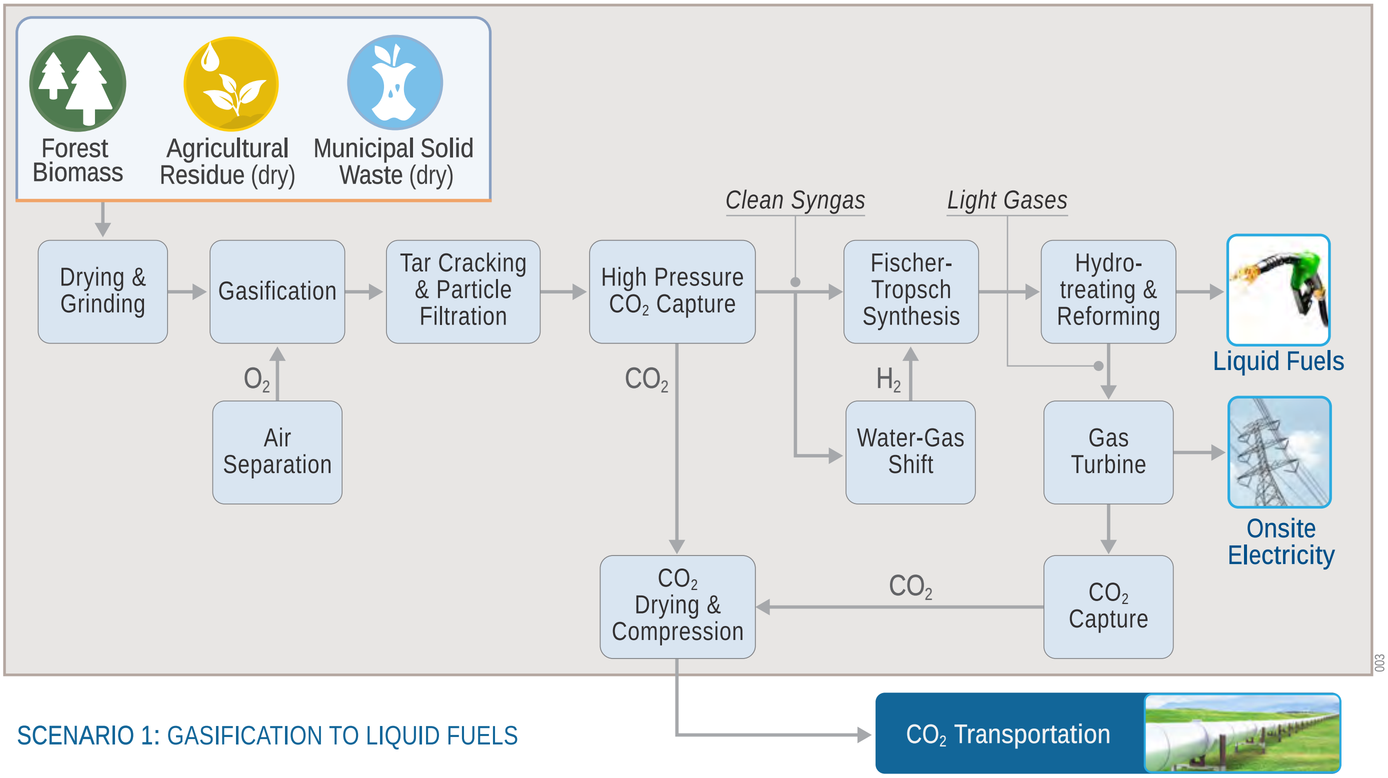


Figure 17. Simplified block flow diagram and system boundary of gasification to liquid fuels via Fischer-Tropsch synthesis with carbon capture. *Hydrogen sulfide is removed along with the CO_2 in the High-Pressure CO_2 Capture process and the two gases will be sequestered together.*

process must be cleaned to avoid poisoning the downstream catalyst. Additionally, CO_2 must typically be removed prior to fuels synthesis to prevent diluting the reactive components of the syngas, which would lead to lower reaction rates and larger reactor sizes. Finally, the ratio of CO to hydrogen in the syngas coming out of the cleanup systems is not directly suitable for synthesis of fuels; the hydrogen content must be increased, necessitating the use of a water-gas shift unit. The product out of the Fischer-Tropsch unit can be refined similarly to crude fossil-derived oil, using additional hydrogen for hydrotreating and reforming reactions. The final products are typically gasoline and diesel blendstocks identical to their fossil-derived counterparts. Overall, about 25% of the carbon contained in the biomass feedstock ends up as carbon in the liquid fuel, with the remainder of the carbon being converted to CO_2 during gasification and the water-gas shift reaction. This CO_2 is typically removed from the process, sometimes in a relatively pure form, in order to keep it from interfering with the Fischer-Tropsch process of fuel production.

A number of academic studies have examined gasification of biomass followed by Fischer-Tropsch synthesis to produce liquid fuels. Our analysis is based upon the work by Larson, et al.,[99] which uses a basis of approximately 4,500 metric tons of dry switchgrass per day to produce approximately 5,000 barrels gasoline equivalent. Within their analysis, the light gases produced during the hydrotreating and reforming processes are sent to a gas turbine and steam generator to generate the heat and electricity needed on site. CO_2 is only captured from the Rectisol acid gas (CO_2 + hydrogen sulfide) removal process, which is a refrigerated methanol process that is particularly effective at removing hydrogen sulfide from the raw producer gas. In their design, CO_2 capture is not considered for flue gases coming out of the gas turbine and steam generator, leading to venting of approximately 25% of the produced CO_2. Because this flue gas is at atmospheric pressure and is only 6% CO_2 by mass, it is not suitable for capture by the existing Rectisol process. Therefore, we added an amine unit to Larson et al.'s process to capture 90% of the CO_2 from the power generation flue gases [100], [101]. Based on the large size of a gasification facility, we assumed that it would be located at or near the sequestration site or a CO_2 pipeline, eliminating the need for onsite storage of CO_2. Therefore, to the process described by Larson et al., we added units for CO_2 drying and compression for purposes of calculating costs [100], [101]. Finally, the costs for equipment related to syngas production were updated based on follow-on work from the same group [102]. Figure 17 shows a simplified block flow diagram of the gasification and Fischer-Tropsch process to produce liquid fuels we considered for negative emissions and cost analysis.

Within the state of California, this general type of biomass-to-liquid-fuels process has been developed by Fulcrum BioEnergy, based in Pleasanton [103]. At their Sierra Biofuels plant, located in Storey County, NV, (estimated to begin operation in 2020), 175,000 tons per year of prepared feedstock (prepared from Municipal Solid Waste) will be gasified and then converted into a synthetic crude oil via Fischer-Tropsch synthesis. The gasification system is from ThermoChem Recovery International. Once fully operational, the plant will produce 11 million gallons of synthetic crude oil per year that will be processed by Marathon Petroleum into transportation fuel. The resultant liquid fuels will have a lifecycle emissions reduction of approximately 80% compared to their fossil counterparts [104].

Scenario 2: Gasification with Water-Gas Shift to Hydrogen

Formation of hydrogen from syngas occurs via water-gas shift, which converts carbon monoxide and water into CO_2 and hydrogen. This is the fuel-producing pathway that has the largest potential quantity of CO_2 that can be captured because the fuel produced (hydrogen) does not contain carbon—essentially, the energy carrier is separated from the carbon. Water-gas shift, along with steam reforming of methane, is an important reaction for industrially producing hydrogen, particularly in ammonia synthesis and fossil fuel refining, and it is used as described above in adjusting the CO-to-hydrogen ratio for converting syngas into Fischer-Tropsch liquid fuels. The catalysts used for water-gas shift can be formulated to be tolerant of sulfur species, so the shift reaction can be performed before removing the acid gas (CO_2 + hydrogen sulfide) components. This allows nearly all the CO_2 produced in this process to be captured in a single step.

Production of hydrogen also aligns with the California Energy Commission's Clean Transportation Program, established by California AB 118 and extended through 2024 by AB 8. The use of renewable biomass for this production of hydrogen is supported by California SB 1505, which requires that at least 33.3% of the hydrogen produced for transportation must be made from renewable energy sources. An analysis by Drs. Scott Samuelsen and Jeffery Reed of the UC Irvine Advanced Power and Energy Program suggest that renewable hydrogen demand in California by 2045 could be between 1.2 and 4.0 million tons annually, and that thermochemical production of hydrogen (i.e., via gasification and water-gas shift of renewable biomass sources) will supply a large fraction of that hydrogen, alongside water electrolysis and reforming of biomethane [105]. Assuming all of the available and applicable biomass is used for this scenario, our analysis below indicates that 3.8 million tons of hydrogen could be

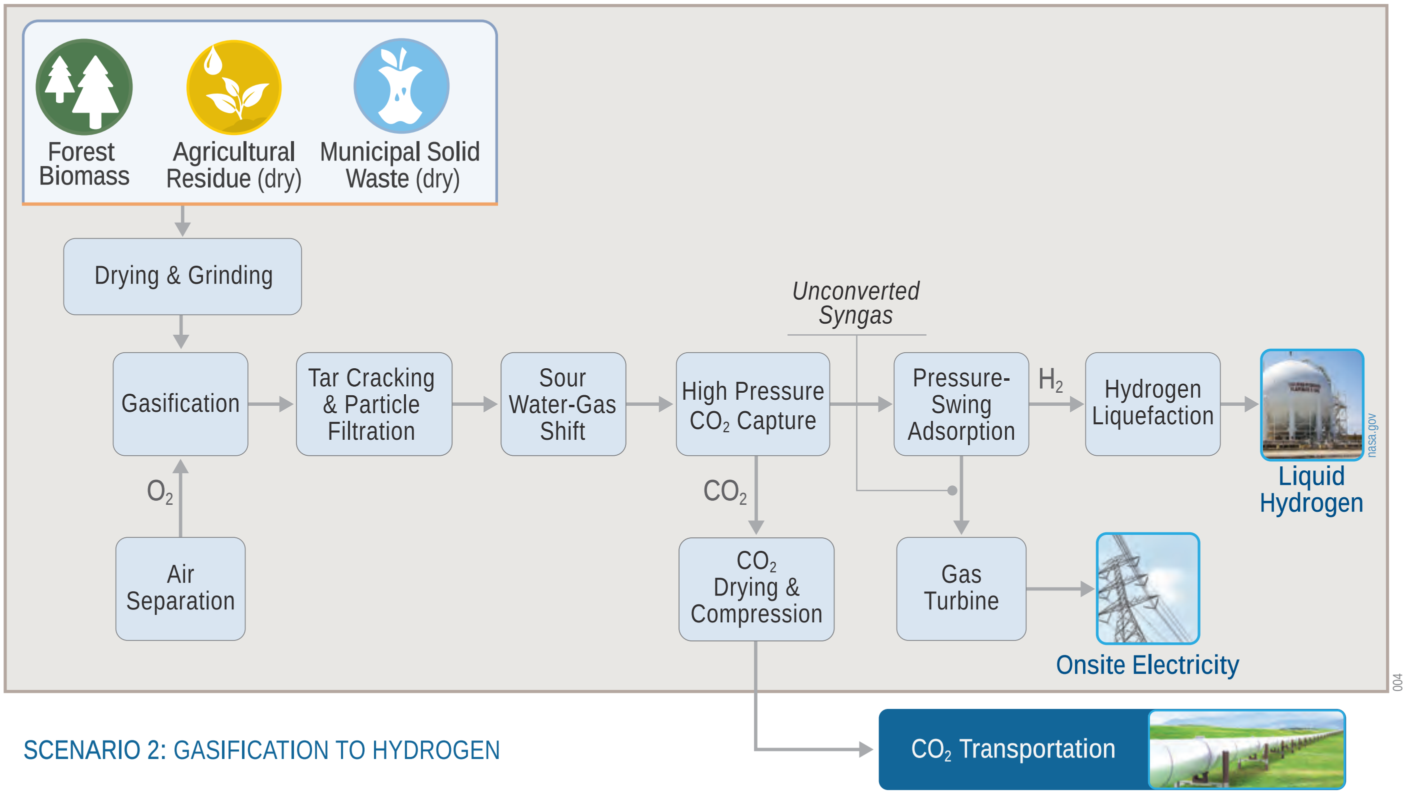


Figure 18. *Simplified block flow diagram and system boundary of gasification to hydrogen via reverse water-gas shift with carbon capture. Hydrogen sulfide is removed along with the CO_2 in the High-Pressure CO_2 Capture process and the two gases will be sequestered together.*

produced annually via this route, supplying a significant portion of the renewable hydrogen demand for the state. Thus, hydrogen production from biomass gasification is worthy of significant consideration due to its alignment with these programs, while also being able to sequester significant amounts of CO_2.

The major drawback for such a significant buildout of hydrogen capacity is related to hydrogen transportation. The Department of Energy Fuel Cell Technologies Office has identified that transportation of liquid hydrogen, as opposed to compressed gaseous hydrogen, is the most efficient in the absence of pipelines, for high volumes of hydrogen production.[106] However, hydrogen liquefaction is expensive and energy intensive because the hydrogen must be cooled below −253° C, the atmospheric boiling point of hydrogen. Development of hydrogen pipelines would allow hydrogen to be easily transported as a compressed gas, and buildout of these pipelines could be accompanied by a complementary buildout of CO_2 pipelines, since large facilities producing hydrogen will also be producing large amounts of CO_2 for geologic storage. Alternatively, a portion of the compressed hydrogen could be sold for blending into the existing natural gas grid, albeit at a lower value than purified hydrogen. It is estimated that the natural gas grid can safely accommodate approximately 20% to 30% hydrogen by volume [107]. Our analysis indicates that approximately 1.5 trillion cubic feet of hydrogen could be produced annually. Based on the 2.1 trillion cubic feet annual natural gas consumption in California, [108] 30% to 40% of the hydrogen that could be produced via our scenario could be safely blended into the natural gas grid. This can provide an outlet for the hydrogen produced from early builds of gasification to hydrogen facilities, prior to construction of a hydrogen pipeline.

The process for hydrogen production begins similarly to that for liquid fuels production. However, the producer gas can be sent directly to a water-gas shift unit, where the carbon monoxide is reacted with water and converted into CO_2 and hydrogen. This results in almost all of the carbon in the feedstock being converted to CO_2, prior to capture by the Rectisol process. The hydrogen is purified via pressure-swing adsorption and then pressurized or liquified for transport. Overall, upwards of 95% of the carbon contained in the feedstock can be captured as CO_2.

Several academic studies have examined large-scale hydrogen production from biomass gasification [99], [109]–[113].

Our analysis is based upon the work by Larson, et al.,[99] which uses a basis of approximately 4,500 metric tons of dry switchgrass per day, which is the same basis for the study on liquid fuels production above, producing approximately 375,000 kg of hydrogen per day. Within their analysis, unconverted syngas and hydrogen that slips by the pressure-swing adsorption process are sent to a steam turbine generator to generate the heat and electricity needed on site. As above, the gasification facility was assumed to be located at or near a sequestration site or CO_2 pipeline, eliminating the need for onsite storage of CO_2; CO_2 drying and compression units were still needed however [100], [101]. In addition, the process described by Larson, et al. suggests compression of hydrogen for transport; in light of the discussion above, considering the size of the production facility in this analysis, we have removed the hydrogen compressor and included hydrogen liquefaction units and on-site storage for 1 day's production of liquid hydrogen, to allow a buffer for filling liquid hydrogen trucks [93], [94]. This significantly increases the capital and operating costs over that calculated by Larson, et al., but is necessary for adoption of large-scale hydrogen production without assuming concurrent buildout of hydrogen pipelines. As a separate scenario, if the facility were located at a hydrogen pipeline, the need for liquefaction and on-site storage would be eliminated, and the hydrogen would only need to be compressed to pipeline pressure. This separate scenario is considered in the section on sensitivity analysis and will be discussed later. As above, the costs for equipment related to syngas production were updated based on follow-on work from the same group [102]. Figure 18 shows a simplified block flow diagram of the gasification and water-gas shift process to produce hydrogen we considered for negative emissions and cost analysis.

Within the state of California, Clean Energy Systems, based in Rancho Cordova, has been investigating production of hydrogen as a byproduct of their Carbon-Negative Energy systems [114]. Their Kimberlina Power Plant will be able to process 300 tons of agricultural biomass per day and predominantly produce electricity using their oxy-combustion system. Hydrogen will be produced as a byproduct and 485 tons of CO_2 per day will be captured, with plans for permanent geologic storage in the South San Joaquin Basin. The CO_2 from the oxy-combustion system can be easily captured and sequestered. Other plant options are also currently being considered by Clean Energy Systems, up to 1,200 tons of biomass per day [115].

Scenario 3: Gasification with Syngas Combustion to Electricity

Rather than creating a chemical fuel from biomass-derived syngas, the syngas can be combusted to create electricity via a combined cycle. If the combustion is performed with air, the resultant CO_2 will be diluted by nitrogen, and so a CO_2 capture unit is necessary. Other power generation cycles could being considered—for example, oxy-combustion of syngas could be

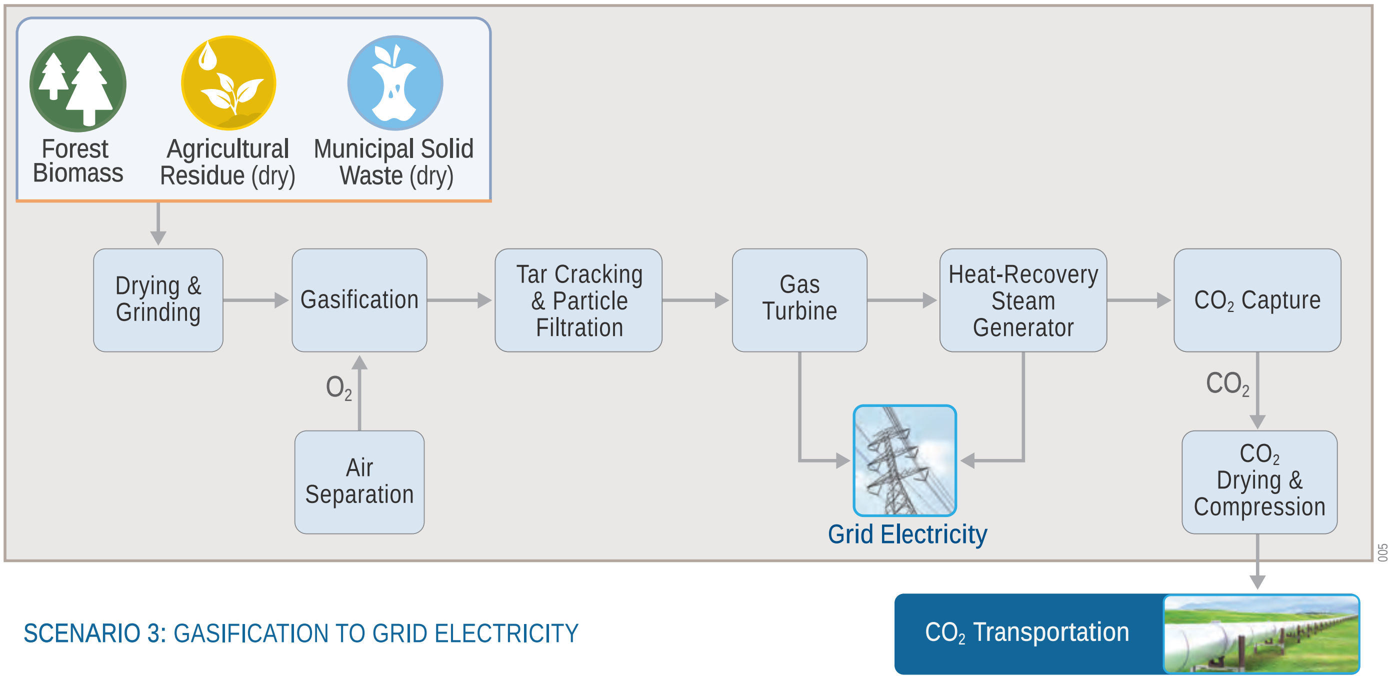


Figure 19. *Simplified block flow diagram and system boundary of gasification to grid electricity via combined cycle power generation with carbon capture.*

followed by the Allam cycle, which would remove the need for a post-combustion acid gas capture unit but would require inclusion of an air separation unit.

Combustion of syngas is more thermodynamically efficient than direct combustion of the biomass (see next section) but it is more capital intensive. If electricity were valuable, the increased electricity output for syngas combustion could outweigh the increased capital cost. This does not seem likely, however.

The analysis here is based upon the work of Jin, et al.,[116] which uses a basis of approximately 4,500 metric tons of biomass per day to generate 440 megawatts electricity. In this work, the syngas is combusted in air and electricity is generated by combined cycle. This technology is well-known and established, particularly at large scale. To purify the CO_2 prior to geologic storage, we added an amine unit to the process from Jin, et al.[100], [101] We assume the amine process will capture 90% of the CO_2 in the flue gas stream. We did not consider Rectisol in this case because the flue gas here is close to atmospheric pressure, whereas physical absorption capture systems are more favorable at elevated pressure. As above, we updated the costs for equipment related to syngas production based on follow-on work from the same group [102].

Though the process modeled here uses combustion of syngas followed by an amine process to capture the CO_2, oxy-combustion could be used instead, as suggested by Clean Energy Systems, or pre-combustion capture by first converting the syngas to hydrogen. However, development and demonstration of pre-combustion capture, oxy-combustion, and other power cycles at large scales is still needed. Figure 19 shows a simplified block flow diagram of the gasification and syngas combustion process to produce grid electricity we considered for negative emissions and cost analysis.

This type of process has been demonstrated commercially around the world with a large majority of facilities being located in Europe; a database of these facilities is maintained by the International Energy Agency Bioenergy Task 33 [117]. However, these bioenergy plants do not capture and sequester their CO_2 after combusting the syngas.

Scenario 4: Direct Biomass Combustion to Electricity

The last process considered here is traditional bioenergy with carbon capture and storage, BECCS. In our analysis, we do not consider production of crops specifically for energy production as is often done in BECCS analyses, as this would result in land-use changes, potentially with net positive emissions as pointed out by other analyses [118]. Rather, this analysis uses the same sources of biomass that have been considered for gasification and described in Chapter 3.

Though biomass combustion is not directly related to gasification, it employs a similar concept. In this process, biomass is burned in a boiler to produce steam, which is then used to generate electricity. CO_2 in the boiler effluent can be captured and sequestered, typically by an amine process. As noted above, biomass combustion is much simpler than

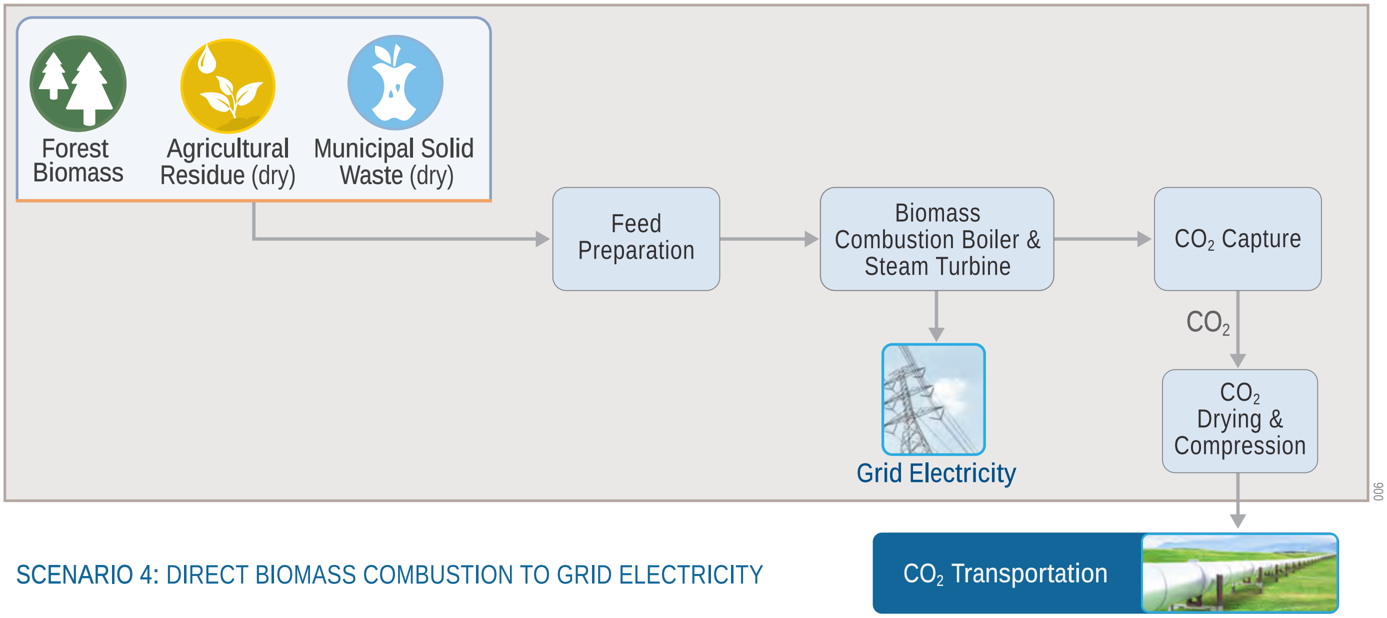


Figure 20. *Simplified block flow diagram and system boundary of direct combustion of biomass with production of electricity via steam turbine with carbon capture.*

gasification with combustion, leading to lower capital cost, at the expense of some energy conversion efficiency.

The analysis here is based on the work of Jin, et al.[116] using the same basis of approximately 4,500 metric tons of biomass per day to generate 300 megawatts electricity. In this work, the biomass is combusted using air, though we note that oxy-combustion of biomass could result in a CO_2 stream that could be dried and compressed directly for sequestration. In this case, addition of an air separation unit would be required. Electricity is generated here using a Rankine steam cycle. For this analysis, we added an amine unit, followed by CO_2 drying and compression to the system, and 90% of the CO_2 in the flue gas was assumed captured [100], [101]. Figure 20 shows a simplified block flow diagram of the biomass combustion (bioenergy with carbon capture and storage) process to produce grid electricity we considered for negative emissions and cost analysis.

Combustion of biomass to generate electricity is already performed around the state of California, with a database maintained by the California Biomass Energy Alliance [119]. These facilities range in size from 10 to 50 megawatts, much smaller than the facility considered here, and existing facilities do not perform carbon capture. They utilize all forms of dry biomass considered here—forest biomass, agriculture residues, and municipal solid wood waste. As with other industrial sources of CO_2, installing capture units on existing facilities should be considered alongside buildout of new capacity.

In addition to the pathways mentioned above, we considered two other gasification-to-product pathways that are potentially viable, methanation and syngas fermentation, but resulted in a lower amount of sequesterable CO_2 and we lacked the information to analyze them fully.

Methanation: the CO_2 and carbon monoxide in cleaned syngas could be fed to a methanation reactor, where these species react with the hydrogen already present in syngas to form methane. However, the amount of hydrogen for complete methanation of the carbon species in the syngas is larger than the amount of hydrogen contained in the syngas, resulting in incomplete conversion of CO_2 and carbon monoxide. We estimate that approximately 33% of the carbon contained in the feedstock can end up in methane through this pathway. After separating the methane, it can go through similar pathways as have been determined for the gaseous waste feedstocks, including injection into the pipeline as renewable natural gas. This strategy is being pursued in California by San Joaquin Renewables, in a partnership with Frontline Bioenergy, to convert orchard residues into renewable natural gas [120], [121].

Syngas Fermentation: using microorganisms, raw syngas can be converted into fuels and chemicals via fermentation. In principle, the products from syngas fermentation are dependent on the specific microorganism used; primarily studies have focused on ethanol production. The common feature of the microorganisms is that they require the presence of a reductant (hydrogen) or a reduced form of carbon (carbon monoxide), making syngas the ideal feed. Syngas fermentation processes are also more tolerant of sulfur in the feed, unlike metal catalyst that used in, for example, Fischer-Tropsch synthesis. Though there are no commercial entities in California pursuing this strategy, LanzaTech has a commercial facility in China which is producing ethanol from syngas coming from steel manufacturing. In principle, syngas fermentation could be added onto a biomass gasifier, which is richer in carbon monoxide and hydrogen [122].

Fast Pyrolysis

Pyrolysis is a thermochemical conversion process operating at lower temperatures and pressures than gasification, and can decompose biomass into gas, liquid and solid products. Varying operation temperature and residence time can shift pyrolysis product distributions. Higher process temperatures and shorter residence times convert more biomass into the gas phase, while lower process temperatures and longer residence times produce more solid product, known as biochar [123]. For our evaluation, liquid pyrolysis oil was assumed to be the most valuable product and therefore fast conditions optimal for pyrolysis oil were considered.

Non-condensable gases and solid biochar are two major byproducts in addition to liquid pyrolysis oil. The gases mainly consist of carbon monoxide, CO_2, and light hydrocarbons that can be combusted onsite to provide heat and power for the system [124]. Biochar is a porous, carbon-rich charcoal whose yield could range from 10-20 wt.% depending on feedstock types and operation conditions [125]. There are two common application uses of the biochar: combustion for energy, and soil amendments [126], [127].

Fast pyrolysis is a process sub-category of pyrolysis that rapidly decomposes biomass with a high heating rate and reaction temperature, around 500° C, to maximize the liquid yields. Bio-oil, which is a complex mixture of oxygenated hydrocarbons and water, is major liquid product that can account up to 75 wt.% of biomass on a dry basis [128]. The resulting bio-oil can be physically, chemically, and catalytically upgraded into various products. We focused on different pathways by upgrading bio-oil into liquid transportation fuels, hydrogen, and heat and power. There are a few commercialized fast pyrolysis companies around the world,

PYROLYSIS OVERVIEW

- Inputs: forest biomass, low moisture agricultural residue
- Potential products: liquid fuels, hydrogen, heat and power, biochar
- Key points: medium maturity technology that may become economical as more units are built.
- Could capture between 18-56 million tons of CO_2 per year at \$8–\$195 per ton of CO_2 depending on biomass source, end product and technology learning

mostly located in Europe, Canada and United States. The plant sizes range from 40–240 metric tons per day dry biomass throughput [129]. Fortum, EMPYRO, and ENSYN are large fast pyrolysis to bio-oil production companies [130], [131], [132]. Currently, most of the bio-oil is combusted in engines or co-fired with fossil fuels [133].

The process of biomass conversion into different final products via fast pyrolysis and subsequent upgrading consists of 1) biomass pretreatment, 2) fast pyrolysis, 3) product separation and 4) upgrading. Only low moisture biomass is considered for fast pyrolysis, which mainly includes forest biomass, dry agricultural waste and food & fiber processing residue in this study. The moisture content of different categories of feedstock is presented in Table 17 in Chapter 3. We assumed that biomass is received at a moisture content of 20 wt.% at the plant gate and dried to less than 10 wt.%. Additionally, the process requires that chopping and grinding processes to reduce the biomass size to less than 3 millimeters. The pretreated biomass is then sent to a pyrolysis reactor operating at 500°C and ambient pressure [134]. The pyrolysis vapor is condensed and separated into gas, liquid and solid products. We apply subsequent upgrading processes and CO_2 capture systems in order to realize the maximum carbon reduction potential for different products. Three scenarios are discussed as below.

Scenario 1: Fast Pyrolysis to Liquid Transportation Fuels

Bio-oil is a highly oxygenated hydrocarbon mixture. Upgrading bio-oil into drop-in transportation fuels requires a comprehensive deoxygenation process that is commonly used in the crude oil refining industry [135]. Figure 21 describes the simplified block flow diagram for this biomass to liquid fuel pathway. As shown in Figure 21, bio-oil is first recovered into heavy, middle and light fractions via a fractionation system. The light bio-oil fraction mainly consists of aqueous phase light hydrocarbons, which are sent to a methane steam reforming system to provide hydrogen for the hydrotreating

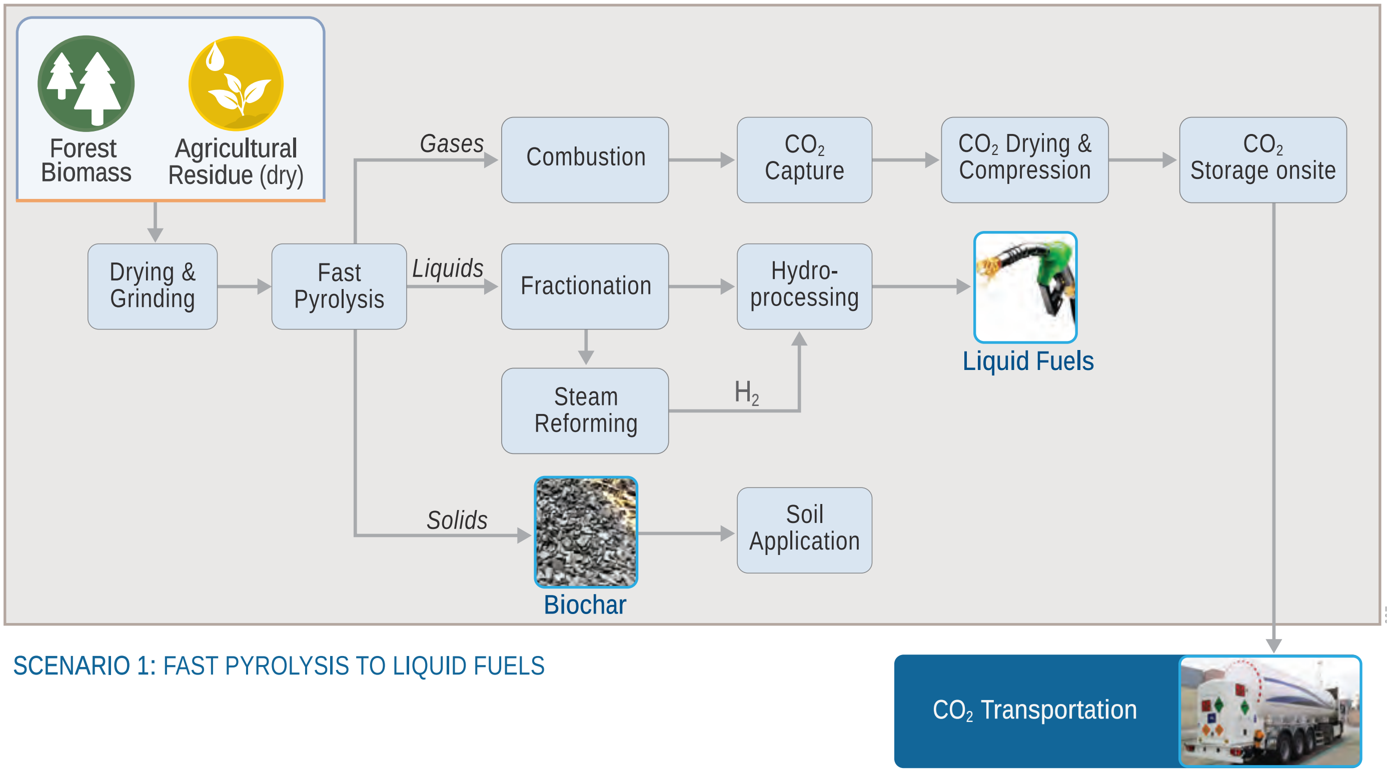


Figure 21. *Simplified block flow diagram and system boundary of fast pyrolysis to liquid fuels with carbon capture.*

and hydrocracking system. The heavy and middle oil fractions are deoxygenated within stepped hydrotreating and hydrocracking units to produce gasoline and diesel range fuels. Non-condensable gases are combusted onsite to produce heat for system use, while biochar is applied to the soil [136]. Biochar properties such as carbon content vary by feedstock and pyrolysis operation conditions. Moreover, the impacts of applying biochar to the soil vary with feedstock, soils, weather conditions, and are still under experimental investigation [137]. In this study, we assume a biochar carbon content of 51% for all feedstocks and that 80% of the carbon remains in the soil for 100 years, which we consider to be a negative emission [138]. We applied a carbon capture system to capture the CO_2 from non-condensable gas combustion with 90% capture efficiency in order to maximize the negative carbon emissions potential. Subsequent CO_2 drying & compression and onsite storage systems are scaled based on CO_2 flow rates [91].

To calculate costs, we assumed a plant with a size of 2,000 metric tons per day of biomass in order to understand the system costs and carbon emissions [89]. We estimate the carbon sequestration potential to be 12 and 6 million tons of CO_2 equivalent per year for forest biomass and agricultural waste, respectively, based on their annual feedstock availability in 2045.

Scenario 2: Fast Pyrolysis to Hydrogen

Bio-oil upgrading into hydrogen consists of bio-oil reforming, followed by the water-gas shift reaction and hydrogen purification process, as shown in Figure 22. Bio-oil reforming is an endothermic process that currently requires carbon-based fuel combustion to provide heat. Currently catalytic steam reforming is the predominant technology to produce hydrogen from bio-oil [139]. Coke formation on the surface of the catalyst during the bio-oil reforming process is a challenge. Therefore, efficient catalysts are required and have been investigated including both noble metal catalysts such as platinum, ruthenium, and rhodium which resist coke formation, and earth-abundant catalysts based on nickel [140], [141]. Gases from the bio-oil reformer are cleaned to remove particles via cyclones, then sent to compressors and coolers to increase pressure and decrease temperature for the subsequent water-gas shift reaction. The water-gas shift reaction increases H_2 production by converting carbon monoxide into CO_2 using steam. Hydrogen is purified using pressure swing absorption with a recovery rate of 80% and compressed for onsite storage [142]. Off-gases from pressure swing absorption unit are combusted to provide onsite heat and captured for CO_2 sequestration. We added a subsequent CO_2 drying and compression to the existing pyrolysis-to-H_2 system. For ready comparison with the gasification to hydrogen process, hydrogen liquefaction and storage was also added.

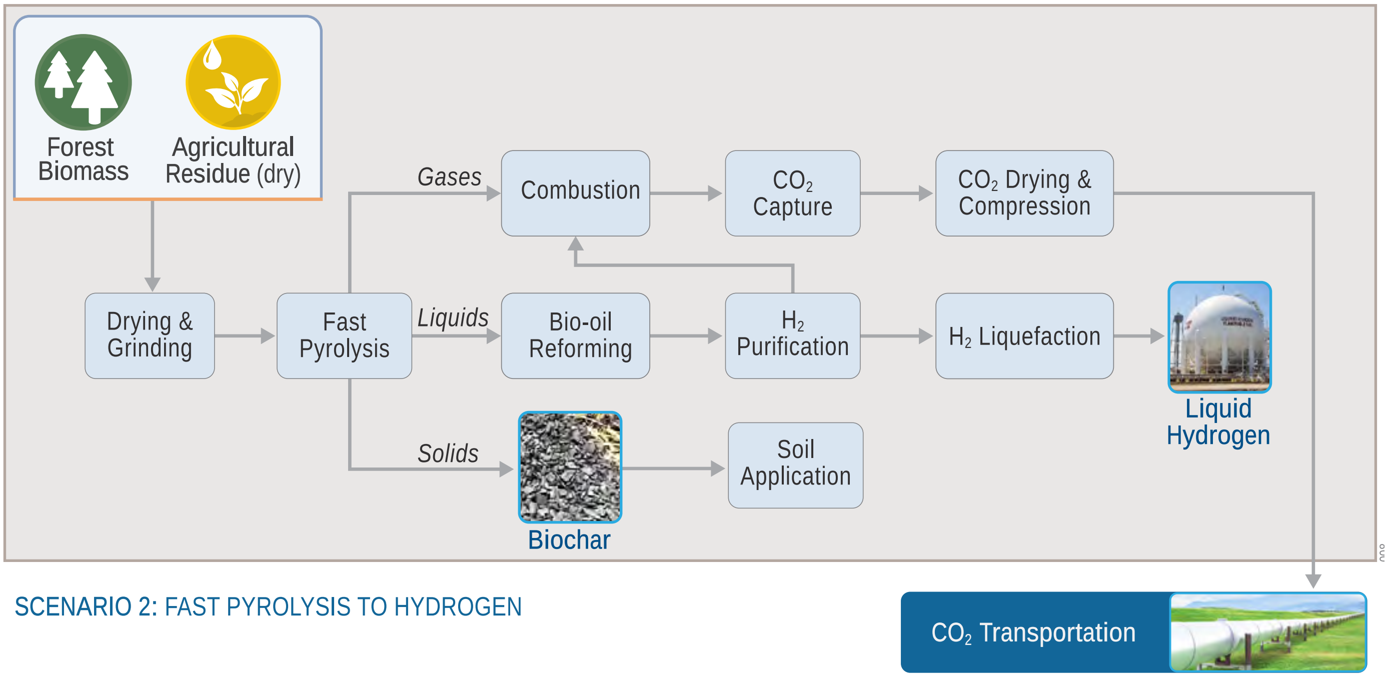


Figure 22. *Simplified block flow diagram and system boundary of fast pyrolysis to hydrogen with carbon capture.*

Continuous hydrogen production from bio-oil steam reforming is still under investigation by experimentalists. Here we gathered the capital and operating costs for a fast pyrolysis plant at scale of 2,000 metric tons per day dry biomass for hydrogen production [258]. Biomass conversion to hydrogen with a carbon capture system has a significant carbon sequestration potential, 36 million and 17 million tons of CO_2 equivalent for forest biomass and agricultural waste, respectively.

Scenario 3: Fast Pyrolysis to Electricity Production.

To produce electricity using fast pyrolysis, bio-oil is produced from the fast pyrolysis system as described above. Subsequently, the bio-oil is combusted in boilers & furnaces for heat production; this pathway has been demonstrated as supplemental firing in a power plant [143]. The bio-oil can also be combusted in a diesel engine for bio-oil to electricity production (Figure 23). Bio-oil has been experimentally demonstrated to burn well in diesel engines with a small amount of auxiliary diesel fuel for bio-oil ignition [144]. Seven and a half percent of the energy supplied to the engine is assumed from supplementary diesel fuel. High temperature uses for bio-oil could lead to char/coke formation that might block the fuel injection system [145]. Methanol is used as a solvent to flush the injection system to overcome the blocking issue. Dual fuel diesel engines and generators have been used for this bio-oil to electricity system [146], [147]. We make similar assumptions for gas and solid byproduct as the pyrolysis pathways: non-condensable gases are combusted for onsite heat, while biochar is sequestered into soil. All onsite electricity required for the whole system is provided from total generated power.

There are different scales of electricity production from pyrolysis oil. In this study, we adopted a 20 megawatts net power plant from Bridgewater et al.[147] which requires a dry woody feedstock input of 329 metric tons per day. We estimate the annual negative carbon emission potential as 38 million and 18 million tons of CO_2 equivalent for forest biomass and dry agricultural residue, respectively.

There are other possible end use applications of bio-oil. One of the possible scenarios is utilizing fractionated bio-oil as a bio-binder that is comparable to asphalt binders mainly derived from petroleum for pavement materials. However, we are not investigating this bio-asphalt scenario here due to lack of accessible data.

Hydrothermal Liquefaction

Hydrothermal liquefaction is a thermochemical conversion of biomass into liquid oil, aqueous phase, solid and gas products in a hot, pressurized water environment under moderate temperatures of 250-370°C and pressures of 4-25 MPa (40

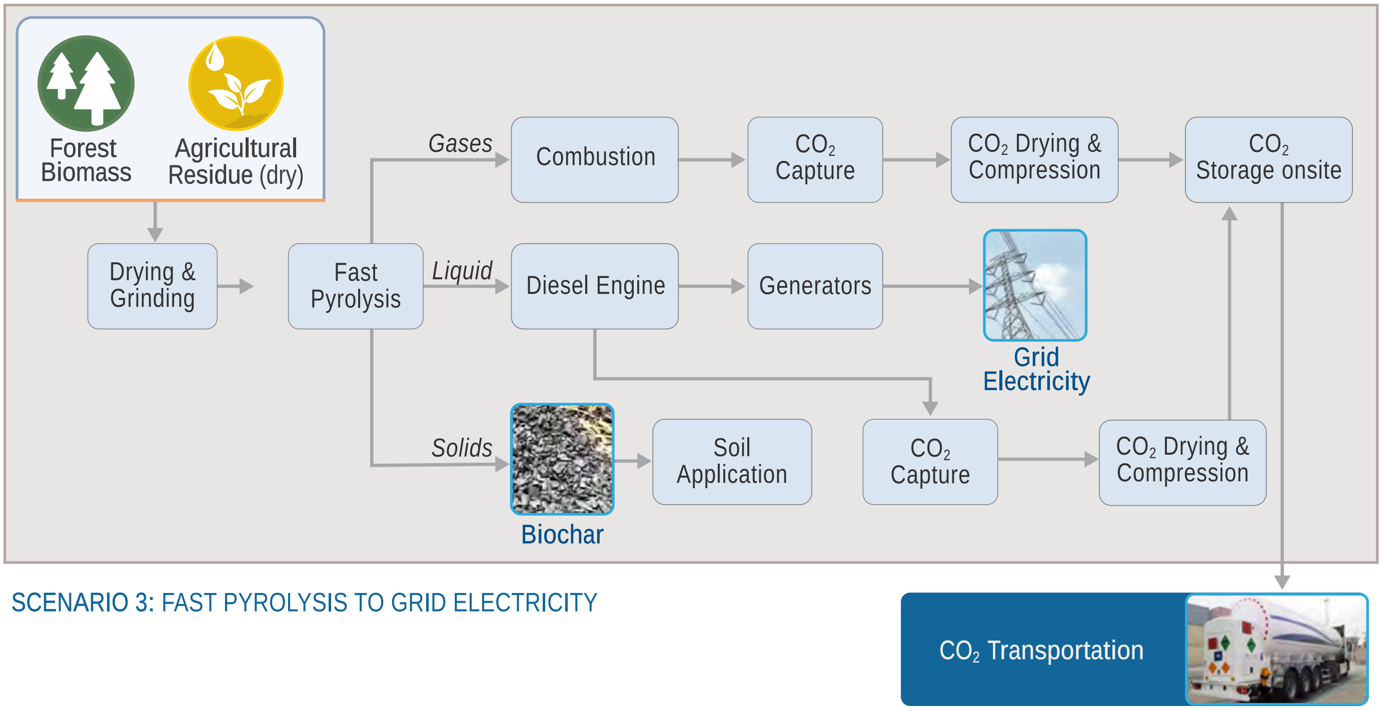


Figure 23. *Simplified block flow diagram and system boundary of fast pyrolysis to electricity with carbon capture.*

to 250 atmospheres) [148]. It is particularly appropriate for high-moisture biomass. Hydrothermal processing consists of three sequential stages with different operation conditions. Hydrothermal carbonization occurs at temperature below 250° C and forms a hydro-char similar to low rank coal. The process at an intermediate temperature of 250–370° C is hydrothermal liquefaction that produces liquid oil known as biocrude. Hydrothermal gasification reactions dominate the process at temperatures higher than 370°C, and gaseous products are formed. Hydrothermal liquefaction processes can take place both in batch and continuous flow reactors [149].

Biocrude is the major product from hydrothermal liquefaction. It is less oxygenated and has less dissolved water than pyrolysis bio-oil. However, a subsequent deoxygenation process is still required in order to upgrade the biocrude into transportation fuels [150]. Additionally, a significant amount of organic materials exist in aqueous phase byproducts from hydrothermal liquefaction. The aqueous phase can be recycled back to hydrothermal liquefaction reactor to increase biocrude yields. Researchers have proposed other aqueous phase processing options including anaerobic digestion and hydrothermal gasification to recover these organic components into methane and CO_2 off gases [151], [152], [153], [154].

One of the advantages of hydrothermal liquefaction is that unlike gasification and pyrolysis it can readily process a wide range of moisture content biomass, saving energy that would normally be required for biomass drying and size reduction [155]. Both low moisture such as lignocellulosic biomass and high moisture wastewater biosolids can be processed to produce liquid products via hydrothermal liquefaction [156]. However, there remain implementation challenges for feeding high pressure biomass slurries [157].

Scenario 1: Hydrothermal Liquefaction to Liquid Transportation Fuels

In this scenario, we focus on hydrothermal liquefaction of lignocellulosic biomass including forest biomass, dry & wet agricultural wastes, and green waste from municipal solid waste to produce biocrude that can be converted to liquid transportation fuels. Figure 24 is a simplified block flow diagram based on the Pacific Northwest National Laboratory design case, including five major subprocesses of biomass pretreatment, hydrothermal liquefaction, oil upgrading, anaerobic digestion and hydrogen production [158]. We incorporated a carbon capture system to enable storage of process CO_2. Additionally, we assumed that a small portion of solid product that accounts for 3% of the biomass carbon is filtered out from the hot effluent coming

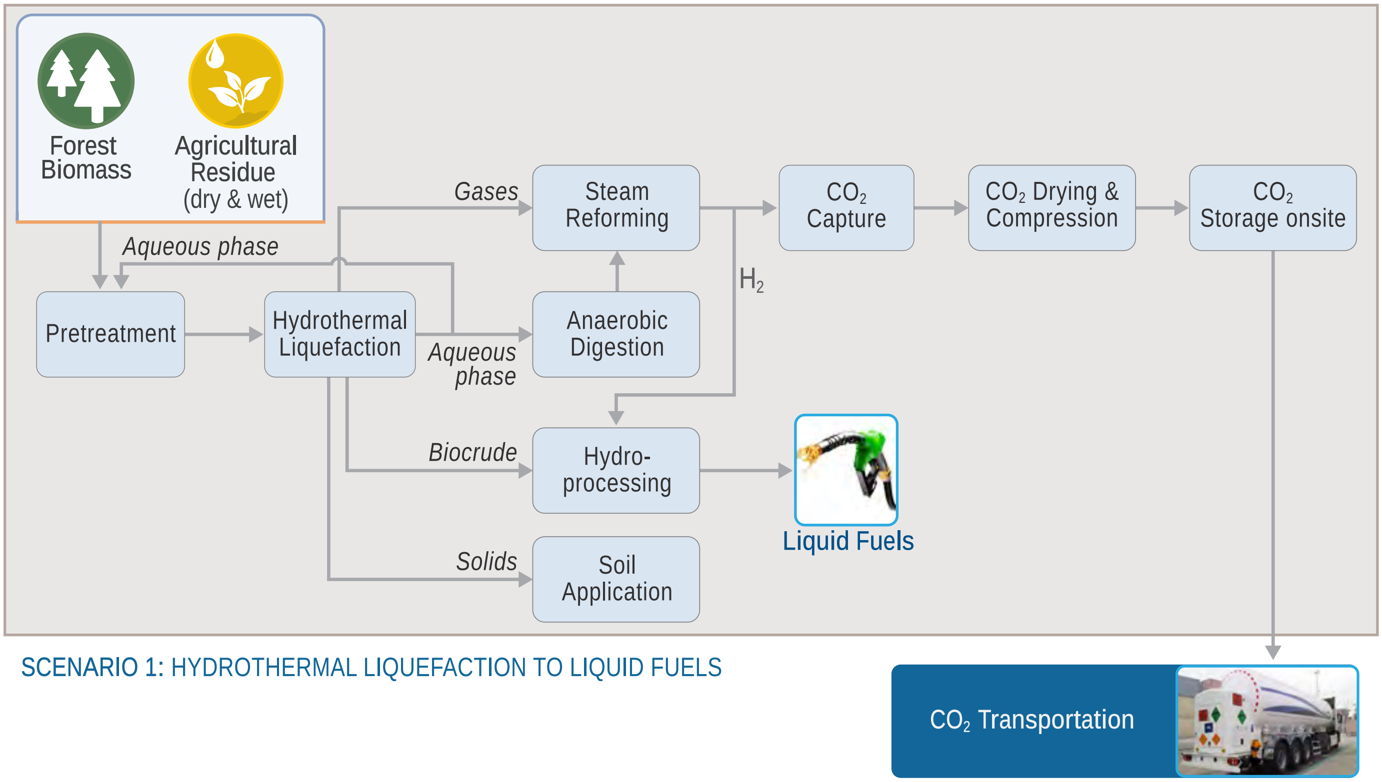


Figure 24. *Simplified block flow diagram and system boundary of hydrothermal liquefaction to liquid fuels with carbon capture.*

HYDROTHERMAL LIQUEFACTION OVERVIEW

- Inputs: forest biomass, low and high moisture agricultural waste, green waste
- Potential products: liquid fuels, hydrogen, heat and power, biochar
- Key points: relatively less mature technology, can process both low and high moisture content biomass
- Could capture and sequester carbon between 1–16 million tons of CO_2 per year at \$253–\$329 per ton of CO_2 depending on biomass source
- The most expensive technological treatment process per ton CO_2 that we evaluated. Therefore, we did not consider hydrothermal liquefaction in cumulative distribution curves in Chapter 9 and assumed green waste would be composted, as described in Chapter 2, rather than treated with hydrothermal liquefaction.

from the hydrothermal liquefaction reactor and applied to the soil for carbon sequestration as biochar. For the purposes of our analysis, we assumed that the biochar resulting from hydrothermal liquefaction has the same degradation rate as that resulting from pyrolysis, as described previously.

First, the biomass and water slurry are preheated and pumped into the hydrothermal liquefaction reactor. Oil, aqueous and gas products are recovered from the cooled and depressurized remaining effluent stream. The gas product stream mainly consists of hydrogen, CO_2, and methane and light hydrocarbons are used in steam-reforming reactor to produce hydrogen for the onsite hydroprocessing system. An 80 wt.% aqueous stream is recycled back to mix with the biomass slurry and carbon in the rest of the aqueous stream and is recovered as methane and CO_2 via anaerobic digestion to provide onsite heat. The oil phase product is upgraded into gasoline and diesel range fuels via a downstream deoxygenation system. We added a CO_2 capture, drying and compression system on the steam reformer to maximize the carbon reduction potential of this hydrothermal liquefaction to transportation fuels system.

For this analysis, we assumed a plant size of 2,000 metric tons per day biomass on a dry basis. We estimate the annual negative carbon emissions potential to range from 1–16 million metric tons of CO_2 equivalent depending on the feedstock.

Biogas Utilization

Biogas utilization from anaerobic digestion can reduce passive methane emissions from decomposing organic waste in California as well as displace some proportion of fossil-based energy either from grid electricity or natural gas. When combined with carbon capture and geologic storage, biogas utilization can also remove CO_2 from the air. The most common use for biogas at wastewater treatment plants and landfills is onsite combustion to produce thermal energy and/or electricity [68], [159]. The prevalence of onsite combustion is due, at least in part, to the fact that biogas can be combusted for energy without first removing the CO_2 component, eliminating the majority of the biogas purification costs [160]. However, when biogas is purified to renewable natural gas,[1] which means it meets purity and heating value requirements set by the California Public Utilities Commission, it can be injected into the natural gas pipeline, displacing natural gas for ready use in the building, transportation, industrial, or electricity sectors.

Anaerobic digestion refers to enclosed anoxic environments in which microbial metabolism converts complex organic waste to raw biogas and biosolids. The anaerobic digestion process used is specific to the type of feedstock and the facility restrictions. For example, facilities that process wastewater, dairy manure or food waste can use dedicated anerobic digestor tanks to produce raw biogas. Biogas can also be captured directly from covered landfills and covered dairy manure lagoons. The feedstock and type of anaerobic process can influence raw biogas composition. Roughly equal amounts of methane and CO_2 account for >95% of the total raw biogas volume; the less abundant contaminant gases are removed prior to any utilization. The nature of particular feedstocks may make certain pre-processing steps (e.g.,

BIOGAS UTILIZATION OVERVIEW

- Inputs: landfill gas, wastewater, dairy manure, food waste
- Potential products: electricity, renewable natural gas for vehicle fuel or pipeline
- Key points: methane product readily integrated into natural gas grid for variety of uses. Plant scales and costs mostly dictated by sizes of existing facilities. Biggest cost driver is biogas upgrading.
- 2.4 to 7.0 million tons of CO_2 per year
- \$84 to \$140 per ton of CO_2

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[1] >970 British thermal units per standard cubic foot per California Public Utilities Commission rules: Decision regarding biomethane tasks in senate bill 840, issued 5/20/19

thermal conditioning, screening or blending) desirable or necessary. While anaerobic digestion practices are different for landfill, manure, food waste, and wastewater treatment plant biomass, the resulting biogas compositions are similar enough that the negative emissions scenarios we considered apply to all sources.

Scenarios for Biogas Use

Negative emissions from anaerobic digestion can result from capturing and storing the CO_2 from the biogas upgrading and/or the combustion of methane at a centralized facility or onsite. In this study, we analyzed four scenarios for processing and utilizing biogas to displace fossil fuels and remove CO_2 from the atmosphere. We chose only to evaluate scenarios that generated a valuable energy product.

One of the challenges with biogas utilization is that biogas is generated by a large number of small sources that are relatively fixed in size and location, in contrast to gasification plants, for example, which can be sized for economy of scale and sited conveniently. The cost of biogas upgrading, CO_2 capture, CO_2 storage, and pipeline infrastructure all depend strongly on the size of the source, which means that not all biogas sources are economic to process. We investigated the range of scenarios described below to compare both the per-facility costs and the system-level quantities of carbon removed and average cost.

Scenario 1: Renewable Natural Gas for Onsite Use

In this scenario, raw biogas is upgraded to biomethane and compressed to storage onsite, then used, typically by vehicles that run on compressed natural gas. The scenario is shown schematically in Figure 25. The CO_2 removed from the raw biogas is compressed and stored temporarily and then picked up by a truck and transported to a CO_2 pipeline for underground injection. The use of biomethane by vehicles is already practiced, though has not been coupled with onsite CO_2 capture. An advantage of this scenario is that there is no need to build pipelines to the biogas facility. This scenario also yields an avoided emissions benefit from displacing fossil natural gas used by the onsite vehicles.

The use of compressed natural gas for onsite use has been described as having the lowest carbon intensity of all biogas utilization scenarios, due to the avoidance of pipeline leaks [160]. In our analysis, we assume an onsite compressed natural gas fueling station at each wastewater treatment plant, landfill, or county level manure site. However, we did not assess whether the amount of compressed natural gas at a facility was matched to fueling needs, nor did we account for the costs of modifying vehicle fleets to operate with compressed natural gas.

Scenario 2: Renewable Natural Gas for Pipeline Injection

The pipeline injection scenario involves upgrading the raw biogas and capturing the resulting process emissions, as shown in Figure 26. This process option includes construction of a pipeline and injection station to link the source to the natural gas network. Compared to Scenario 1, there is a higher cost of capital but a larger and more stable market for the renewable natural gas.

Injection of renewable natural gas into the pipeline network allows for a wide range of end uses, including heating, transportation, manufacturing, and power generation for various sectors, including sectors that are difficult to decarbonize, while displacing fossil-derived natural gas with biomass-derived renewable natural gas. Additionally, pipeline injection leverages existing infrastructure for product

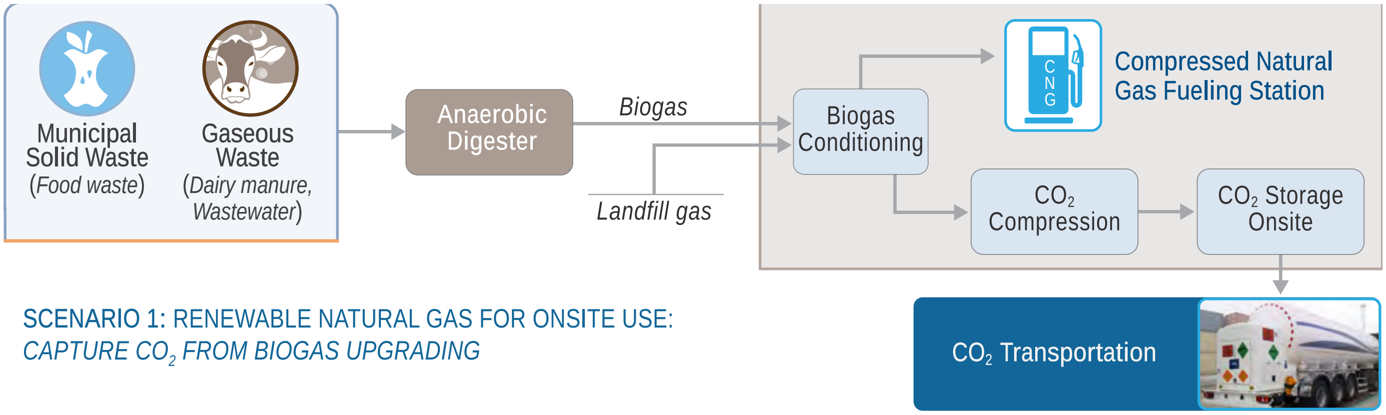


Figure 25. *Simplified block flow diagram and system boundary for scenario 1, renewable natural gas for onsite use.*

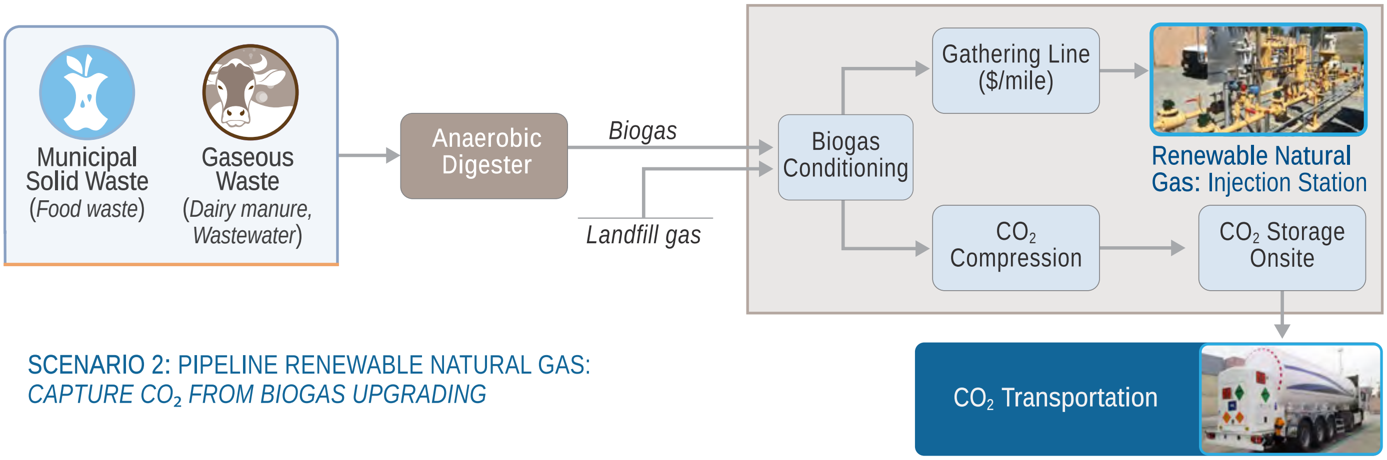


Figure 26. *Simplified block flow diagram and system boundary for scenario 2, renewable natural gas for pipeline injection.*

distribution and power generation. The system boundary for this scenario ends at the injection station and end uses are not considered.

Scenario 3: Electricity Generation in a Central Power Plant

3a. Electricity generation in a central power plant – new build. In this scenario, the process CO_2 from biogas upgrading is not captured, avoiding the cost and logistical challenges of CO_2 collection at many small sources. Instead, the renewable natural gas is transported via the existing gas network to a central location, where a state-of-the-art Natural Gas Combined Cycle power plant equipped with CO_2 capture is constructed. The scheme is shown in Figure 27. The electricity from the power plant is sold to the grid while the CO_2 is sent via pipeline for underground injection. The central power plant takes advantage of an economy of scale for both high efficiency of electricity generation and lower cost of CO_2 capture. The biogas sources and the power plant need not be physically linked; more likely they have a contractual relationship through the natural gas network operator to purchase and provide equivalent quantities of renewable natural gas.

3b. Electricity generation in a central power plant – retrofit. This is the same as scenario 3a, but instead of building a new plant, a conventional Natural Gas Combined Cycle plant is retrofitted with carbon capture. Due to steadily increasing intermittent generation from renewable sources,

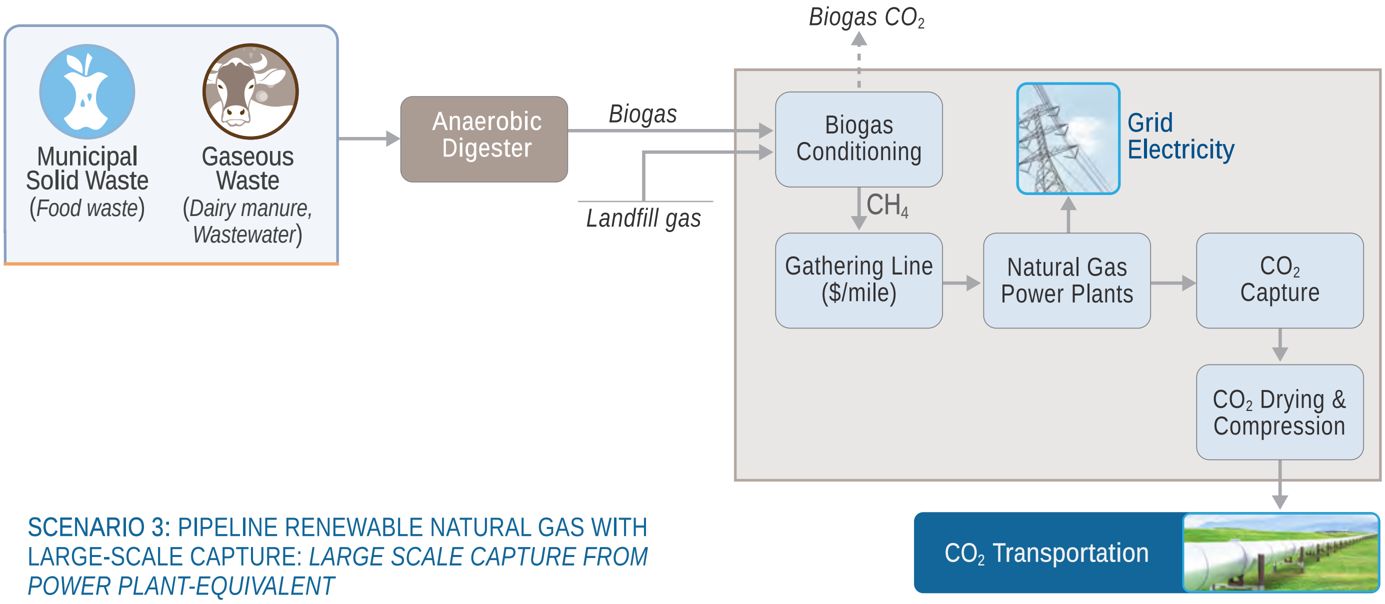


Figure 27. *Simplified block flow diagram and system boundary for scenario 3, electricity generation in a central power plant with large scale carbon capture.*

and to further align with the goals of Senate Bill 100, a number of existing natural gas-fired combined cycle plants may be decommissioned by 2045 due to low capacity factors or high carbon footprint, making them good candidates for this scenario. Compared with Scenario 3a, the retrofit saves on the capital cost of the power plant, though the cost of the retrofit carbon capture unit is somewhat higher than for the capture unit on a new build.

Scenario 4: Electricity Generation in a Central Power Plant + Local CO_2 Capture

Scenario 4 combines local carbon capture from biogas upgrading with carbon capture on a central power plant. The process diagram depicting scenario 4a and 4b shown in Figure 28.

4a. Electricity generation in central power plant – new build and local CO_2 capture. This scenario combines Scenarios 2 and 3a. The power plant is run as described above, but process CO_2 is also collected from the individual biogas upgrading facilities, adding costs of onsite CO_2 compression, temporary storage, and small-scale transport (assessed in Chapter 7). However, this scenario has the potential to remove about twice as much CO_2 from the air per biogas facility since both process CO_2 and biomethane carbon are captured.

4b. Electricity generation in central power plant – retrofit and local CO_2 capture. This scenario combines Scenarios 2 and 3b. It is the same as Scenario 4a except the power plant is an existing natural gas plant retrofit with CO_2 capture instead of a new build.

We did not analyze scenarios involving onsite combustion of raw biogas followed by post-combustion capture. While onsite combustion to generate electricity is currently common, technologies for post-combustion CO_2 capture at small scale are not currently mature enough to estimate the cost. Post-combustion capture is similar to CO_2 capture from biogas upgrading, but the CO_2 concentration is lower (<15% instead of 40—50%) and the separation is from nitrogen instead of methane. If economical small-scale post-combustion CO_2 capture becomes available, it may be preferable to the scenarios above.

Biogas Sources

For all biogas feedstocks, with the exception of manure, the anaerobic digestion infrastructure exists today and is assumed to be fixed in size and location. We estimated costs per facility currently in operation for wastewater treatment plants and landfills. We collected food waste estimates on a per county basis and evenly distributed to currently available anaerobic digestors at wastewater treatment facilities in each county. We did not account for any food waste in counties that have no currently operational wastewater treatment facility and did not add any new digestor facilities to handle food waste.

Manure facilities are smaller than the other source types and generally too small to upgrade the biogas economically at each site. However, unlike landfills and wastewater treatment facilities, cattle operations tend to be geographically clustered. As a result, an existing practice in some manure treatment facilities is to aggregate raw biogas from multiple farms via low pressure, fiberglass pipelines, and then upgrade the gas at a central facility. Accordingly, we analyzed

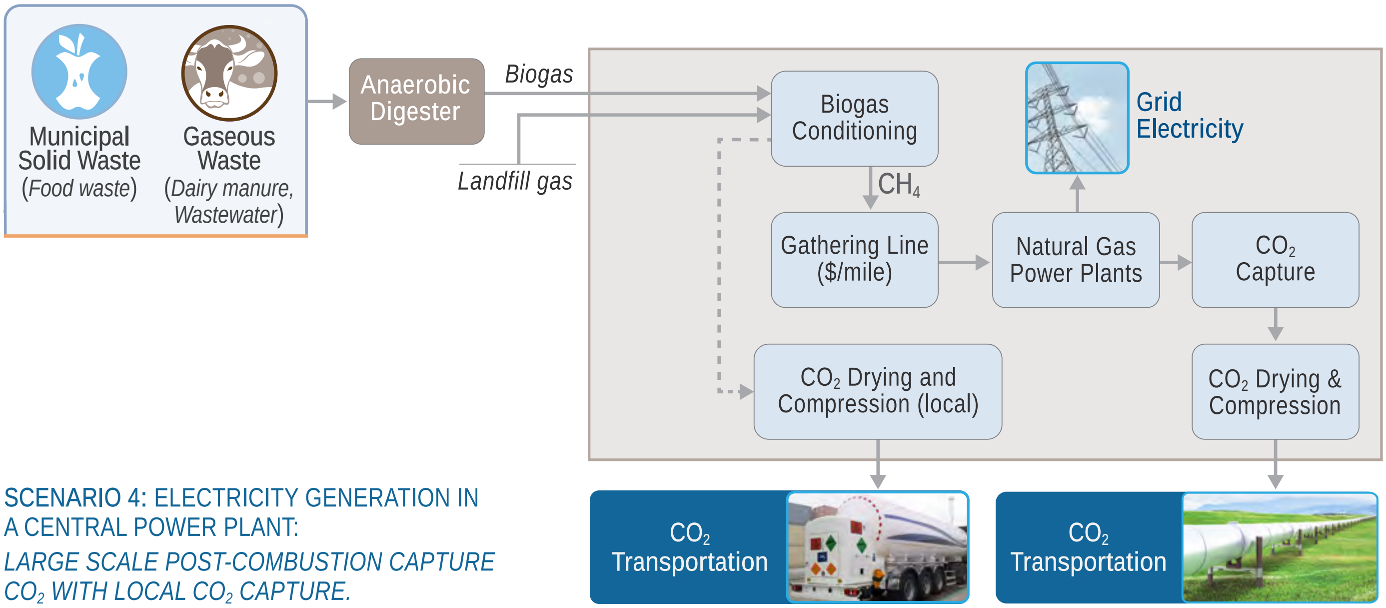


Figure 28. *Process flow and system boundary for scenario 4, electricity generation in a central power plant with large scale CO_2 capture and local carbon capture.*

aggregated cattle populations and associated biogas volume and upgrading cost estimates to facilities with about 10,000 cattle to produce 1 to 3 biogas upgrading facilities in each county with dairy operations [161].

We excluded cost of biogas generation infrastructure (covered lagoons or anaerobic digesters) and biogas collection since current practices or regulations will encourage these practices. For wastewater, >90% of the processed wastewater volume is already treated using existing anaerobic digestion facilities in California. For dairies, landfills, and food waste, SB 1383 requires 40% reduction in methane emissions relative to 2013 levels by 2030 for manure management and 75% less disposal of organic waste in landfills by 2025. These mandated reductions in methane emissions could be achieved by flaring rather than utilizing the methane portion of biogas, therefore we accounted for the production and utilization of renewable natural gas from biogas as avoided emissions. Additionally, we assumed that food waste diverted from landfills (as mandated by SB 1383) will be processed by anaerobic digestion at existing wastewater treatment plants that have extra installed capacity today. This extra installed capacity is likely to be sufficient for at least a large fraction of additional food waste [161], [162]. We did not estimate additional operational costs attributed to food waste at wastewater treatment plants. However, as noted in a recent DOE report “Waste-to-Energy from Municipal Solid Wastes”, [163] aging anaerobic digestion infrastructure that was installed at wastewater facilities shortly after the passage of the Clean Air Act in 1963 will need to be replaced over the next decade, offering the opportunity for wastewater treatment plants to improve anaerobic digestion technology, such as increasing throughput or efficiency beyond what was considered in our analysis.

Estimating Costs

We estimated costs for each of the six scenarios for all biogas facilities and normalized the cost to dollars per ton of CO_2 removed. The cost estimates, including cost curve equations, are detailed in Appendix E and include biogas upgrading and methane compression, local CO_2 compression, local CO_2 storage, pipeline (when applicable), power plant costs (when applicable), and revenues from renewable natural gas or electricity.

Biogas Upgrading Costs

We estimated biogas upgrading costs based on the Environmental Protection Agency’s report Evaluating the Air Quality, Climate, and Economic Impacts of Biogas Management Technologies. The report summarizes capital and operating expenses for biogas facilities at a range of scales and applies multipliers to adjust previous project cost estimates to conditions in California [164]. Biogas upgrading technologies to generate renewable natural gas for vehicle and pipeline use must remove the majority of H_2S, water, nitrogen, oxygen, and CO_2. Technologies available today include pressure swing adsorption, water scrubbing, membrane separation, chemical adsorption, organic physical scrubbers, and cryogenic separation. However, water scrubbing does not produce a pure CO_2 product suitable for sequestration [165]. In this report, we based our cost assumptions (described in depth in Appendix E) on data for installed pressure swing adsorption and membrane technologies that in principle can be tuned to produce a CO_2 stream of sufficient purity for geologic storage (>98%) [166], [167]. We assumed that the biogas was upgraded to a methane concentration of >98% to achieve pipeline qualifying heating values of renewable natural gas, and that 10% of the carbon was lost due to leakage throughout the system boundary, including biogas conditioning, methane or CO_2 compression, and onsite storage [164], [168], [169], [170], [171]. We did not account for the costs of disposal of byproducts from biogas upgrading, such as digestate. Methane recovery rates for commercially available technologies can range from 85 to 99% [168], [164].

For scenarios where CO_2 is captured from the biogas upgrading system, the CO_2 must be compressed and stored onsite for pickup by a tanker truck. Depending on the size of facility, the flowrate amounts to less than one to up to about four trucks per day of CO_2. As will be shown in Chapter 7, these flowrates are unlikely to justify CO_2 pipeline or rail construction, but transport by truck is reasonable.

Power Plant Costs

To estimate the costs of electricity generation and CO_2 capture at a central power plant, we use two baseline performance studies from the National Energy Technology Laboratory (NETL): Chou et al. [172] for the retrofit case and Fout et al [173]. for the new build cases. We use the cases for natural gas combined cycle plants with second-generation aqueous amine capture systems operating at 90% capture rate. There will likely be newer capture technologies available by 2045 (especially for new builds), such as the oxygen-fired Allam cycle design, and these technologies could yield 100% capture at lower cost, but for the purposes of this study, we used the existing, mature technologies.

Both NETL studies provide levelized costs of capital, operation and maintenance, fuel, and other categories per unit of electricity. We adjusted these costs to 2018 dollars and normalize them per unit of CO_2 captured using the power plant heat rates. The key parameters are summarized in

Appendix E. For this estimate, we exclude the cost of fuel, since that is accounted for by the cost of biogas upgrading and transport. The costs of CO_2 transport and storage from the NETL model are also excluded since they are accounted for in Chapter 7. In this case, we use the NETL financial parameters, since they are chosen to be appropriate for private investment in the power sector. Chou et al. [172] provide three retrofit cases for different turbine technologies and we use the average of the three. Between the new build and retrofit cases, the costs differ primarily in the capital cost, which includes the cost of the turbine for the new build case and not for the retrofit cases. In both scenarios, we assume the plant does not operate without the biogas source and carbon removal incentive. The entire plant cost and the entire electricity revenues are included in the calculation.

Results

The distributions of costs for the six scenarios are shown in Figure 29 for the year 2045 (current cost estimates using projected 2045 biogas volumes). The charts order the facilities by increasing cost to produce a marginal cost distribution. The higher the incentive for carbon removal (or acceptable cost, as depicted on the y axes), the more facilities become economic to participate in the scenario. We have marked the cost and corresponding cumulative quantity of carbon removal for $190/ton CO_2. This is the average estimated cost of direct air capture in 2045. We chose this value as the cutoff between which facilities are included and excluded in each scenario. In principle, any facility that wanted to remove carbon at a higher price than this could be undercut by a direct air capture plant. All these costs exclude CO_2 transport and geologic storage.

Table 22 shows scenario-specific parameters along with the quantities of carbon removal resulting from the cutoffs shown in Figure 29. Table 23 presents the weighted-average costs for each scenario, broken out by the seven components of the total cost. We can see that biogas upgrading dominates the total costs in all scenarios, although power plant costs are a

Table 22. *Quantities for biogas scenarios in 2045.*

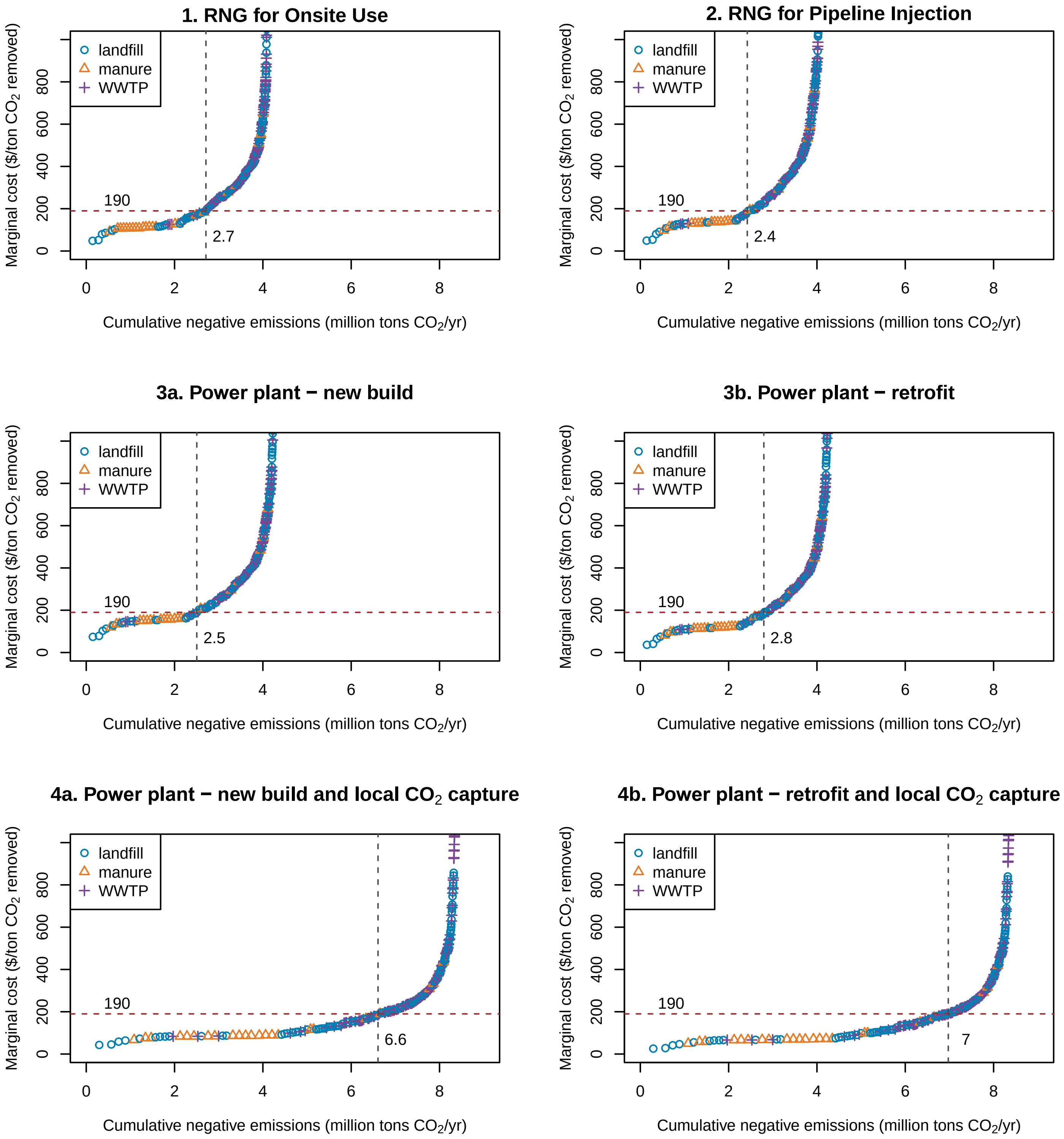
Cost Component	Onsite RNG Use	Pipeline RNG	Power plant – new build	Power plant – retrofit	Power plant – new build and local CC	Power plant – retrofit with local CC
Tons CO_2 removed per ton raw biogas	0.67	0.67	0.70	0.70	1.37	1.37
Fraction of raw biogas processed	0.66	0.59	0.59	0.65	0.79	0.83
Total CO_2 removed (M ton/yr)	2.71	2.42	2.50	2.80	6.61	6.97

Table 23. *Average costs for biogas scenarios in 2045.*

Cost Component	Scenario 1: Onsite RNG Use ($/ton CO_2)	Scenario 2: Pipeline RNG ($/ton CO_2)	Scenario 3a: Power plant – new build ($/ton CO_2)	Scenario 3b: Power plant – retrofit ($/ton CO_2)	Scenario 4a: Power plant – new build and local CC ($/ton CO_2)	Scenario 4b: Power plant – retrofit and local CC ($/ton CO_2)
Upgrading and methane compression	183	176	168	175	100	104
Local CO_2 compression	6	6	0	0	6	7
Local CO_2 storage	3	3	0	0	5	6
Aggregation pipeline	11	12	11	11	5	5
Gathering pipeline	0	13	12	13	7	8
CO_2 capture at power plant	0	0	120	86	61	44
Revenue	-89	-89	-171	-175	-89	-89
Total net average cost	116	122	141	110	95	84

close second in the new build scenarios. This suggests that improvements in biogas upgrading technologies, which are relatively new, can significantly decrease costs in all scenarios.

Taking the quantities and the costs together, we can see that four scenarios offer carbon removal of just under 3 million tons CO_2 per year at costs slightly over \$100/ton CO_2. These options all retain a degree of simplicity by capturing only the process CO_2 component or only the methane combustion CO_2 component from biogas. On the other hand, scenarios that capture both the process CO_2 and methane combustion CO_2 components offer just under 7 million tons of carbon removal at slightly under \$100/ton CO_2. The power plant retrofit case with local CO_2 capture, scenario 4b, offers the highest


1. RNG for Onsite Use

2. RNG for Pipeline Injection

3a. Power plant − new build

3b. Power plant − retrofit

4a. Power plant − new build and local CO_2 capture

4b. Power plant − retrofit and local CO_2 capture

Figure 29. Distributions of cost per ton of CO_2 vs. tons of CO_2 available for each scenario considered. *Quantities associated with these cost curves are shown in Tables 25 and 26.*

removal quantity and the lowest average cost. For reference, scenario 4b produces 1.1 gigawatts of electricity– about 4% of California's consumption in 2018. The quantity of biomethane injected into the natural gas network in this scenario is 84 billion standard cubic feet, or about 4% of 2018 consumption. This is the scenario we include in the cumulative distribution scenarios in Chapter 9.

Due to the versatility of methane as a chemical feedstock and energy carrier, we did not exhaustively evaluate every possible scenario for negative emissions or alternative use for avoided emissions from the utilization of biogas. Several more potential scenarios exist and may emerge in the coming decades. One alternative use for renewable natural gas is for baseload/flexible carbon neutral power generation to back up renewables as California moves toward 100% renewable and low carbon power. This would require the renewable natural gas power plants to operate at low capacity factors, which would presumably make capturing combustion emissions (as considered in Scenarios 3 & 4) uneconomic. We did not evaluate this alternative use and the constraints and economic value it would place on the supply of renewable natural gas, because the focus of this report was to evaluate only pathways for negative emissions.

Our analysis covered scenarios, though not exhaustive, that we considered to be based upon simple pathways and mature technologies. We did not consider CO_2 capture from flared biogas due to the lack of a saleable product, nor did we consider the negative emissions potential of the carbon contained in biosolids, due to their high moisture and low carbon content.

We did not explicitly consider small scale post combustion capture as a negative emissions scenario even though the majority of biogas is currently utilized through onsite combustion and heat/power generation in California. Our reasons for omitting small scale post combustion capture from this analysis were that 1) the lower CO_2 concentration in post combustion capture (<15%) compared to the CO_2 concentrations in raw biogas (40%), likely leads the cost of post combustion capture to be higher than capture from biogas upgrading [174], 2) we were not able to identify information explicitly on the costs associated with small scale carbon capture; this is a research need, and 3) due to the wide range of biogas utilization infrastructure at landfills in California, including pipeline injection, power generation, and flaring, even in some cases all at the same site, evaluating small scale post-combustion capture at landfills would have required that we determine a process configuration at each landfill, which was beyond the scope of this study. We also did not consider alternative uses or downstream processing of renewable natural gas beyond pipeline injection and power generation due to either process complexity or cost uncertainty. Possible alternative scenarios include conversion of methane to vehicle fuel through steam methane reforming and Fischer-Tropsch, conversion of methane to hydrogen and biochar, and others.

Torrefaction

Torrefaction is a thermochemical treatment process for biomass that is employed at ambient pressures and low temperatures in the range of 200–300° C. Biomass torrefaction can improve energy density and reduce the moisture content and oxygen-to-carbon ratio of raw biomass, facilitating subsequent biomass processing steps using other technologies [175]. There are three major products from torrefaction: solid torrefied biomass, liquid condensable volatile organics and non-condensable gases [176]. The solid mass remaining in torrefied biomass is higher in woody biomass (70–90 wt.%) than in agricultural waste (55–72 wt.%) under similar torrefaction operation conditions since agricultural waste biomass contains a higher volatile content [175]. The condensable product stream is mainly composed of water and light organics, while the majority of the non-condensable gases are CO_2 and carbon monoxide [149].

On its own, torrefaction does not produce significant amounts of valuable energy products in the forms we have considered in this report, nor does it produce significant amounts of CO_2. However, torrefaction is widely used as a biomass pretreatment technology and can be coupled with gasification or pyrolysis to produce gas and liquid energy products in addition to heat and power [177]. For example, torrefaction could be performed on the small scale near the biomass sources to produce a dense solid torrefied biomass that would then be used as a soil amendment or transported to a central large-scale gasification or pyrolysis facility. There are a few studies that have investigated the economics of biomass torrefaction under different plant scales from a supply chain perspective; these have reported a torrefied biomass production cost of $17–$45 per metric ton [178], [179]. For the purposes of this report, we determined that further research is needed to assess potential economic and emissions benefits derived from incorporating torrefaction with other biomass conversion technologies on a commercialized scale [180]. An option that could be considered is to simply bury torrefied biomass, but we do not have estimated costs for that process, nor have any associated issues been evaluated, particularly regarding the carbon lifecycle of this process. Torrefied biomass can also be used as a fuel, particularly in cement production [6].

Composting

Composting is a relatively simple and inexpensive method for the (primarily) aerobic biodegradation of organic wastes and is a commonly employed method to process food and garden waste to increase nutrient content in soils, avoiding the need for synthetic fertilizers [181], [182]. Several composting technologies are employed on industrial scales, including open technologies (windrow and mat composting, static pile composting), enclosed technologies (channel and cell composting, aerated pile) and reactor technologies (tunnel composting, rotating drum composting) [183]. The carbon products of composting can include gaseous, (CO_2, methane, nitrous oxide), liquid, and solid phases. These gaseous products, particularly nitrous oxide and methane, have significant global warming potentials, and the uncertainty surrounding the length of time that compost carbon remains in the soil is described in depth in Chapter 2. [184], [185], [186]. Due to this uncertainty, and to avoid overcounting available biomass, we only accounted for the negative emissions potential, due to soil carbon and plant productivity increases, of composting available green waste and digestate from manure anaerobic digestion in this report (described in Chapter 2). We chose to utilize green waste in composting rather than another technological treatment process because we found that the other suitable processing technology for green waste, hydrothermal liquefaction, was prohibitively expensive per ton of CO_2.

Negative Emissions Potential, Avoided Emissions, and the Cost to Capture Carbon

To calculate the negative emissions potential for each technology scenario, we assumed that the entirety of the relevant fractions of the given feedstock were treated by that scenario, where the relevant fractions of each biomass source for each scenario have been explained previously. For example, in determining the negative emissions potential of treating agricultural residue by gasification, we only considered the dry agricultural residues and food & fiber processing residues. The figures below (Figure 30–Figure 33) are separated by biomass feedstock source.

Summing all the negative emissions potentials would lead to extreme over-counting; the maximum negative emissions potential as a result of summing the largest potentials for scenarios with non-overlapping biomass sources, is 83 million tons of CO_2 in 2045. This number is smaller than the 100 million tons of CO_2 mentioned at the beginning of the chapter due to the inability to economically capture 100% of the CO_2, and the formation of carbon-containing products. Additional factors, such as the cost of transporting biomass/CO_2 combined with the distribution of biomass and suitable sequestration sites around the state, or the availability of the biomass, will further reduce the actual amount of negative emissions achievable from biomass sources.

Though not the primary focus of this report, we have considered the emissions associated with fossil resources that may be avoided in 2045 due to their displacement by fuels and energy from biogenic sources. In general, the avoided fossil emissions are calculated using the reference product emissions values in Table 21. However, we acknowledge that existing legislation in California will change the fossil/renewable mix in the future. For example, the Low Carbon Fuel Standard currently targets a 20% reduction in carbon intensity of liquid fuels by 2030. If this trend continues to 2045, it will result in a 35% reduction in the carbon intensity for liquid fuels. For hydrogen, SB 1505 mandates that 33.3% of hydrogen produced for transportation must be from renewable sources. Additionally, we acknowledge that the carbon intensity of fossil-derived products may also decrease over time, for example, if carbon capture and sequestration is performed in tangent with fossil-derived product formation. We make no attempt to forecast how the carbon intensity of the fossil-derived product will change over time.

For our analysis of avoided fossil emissions, we assume that production of liquid fuels or hydrogen from biomass feedstocks will displace a fossil-derived product, rather than attempting to forecast the mixed composition of fossil- and renewable-derived product in California in 2045. Therefore, the avoided fossil emissions are calculated using the product emissions values in Table 21.

The exception to this is for grid electricity. SB 100 mandates that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. Therefore, we assume that there will be no carbon-emitting electricity to displace, and hence that there are no avoided emissions associated with production of electricity from biomass sources. We did not consider the potential to displace carbon-emitting electricity that is not sold at the retail level to end-use customers or that is not procured by state agencies.

Our biomass conversion assessment considers the costs for 1) biomass collection and piling by the roadside, 2) biomass conversion technology, 3) CO_2 capture, drying, compression, and onsite storage where applicable, and 4) product transportation costs when the relevant current product wholesale price includes transportation of product. Costs that are not included are 1) the cost to transport biomass from the roadside to the biomass conversion facility, and 2) the cost to transport CO_2 from the onsite storage container to a CO_2 pipeline or the geologic storage site. These costs will be considered in Chapter 7. Also, avoided fossil emissions are not considered as part of our cost calculations – only the actual negative emissions, i.e., carbon that can be permanently removed from the atmosphere, are counted here. The cost calculation methodology is shown in Equation 2 and Figure 16 and in Appendix D.

In general, scenarios that lead to production of hydrogen or electricity have a higher negative emissions potential than scenarios that produce liquid fuels. This is because, for liquid fuels, part of the carbon contained in the feedstock remains in the fuel, whereas hydrogen and electricity do not contain carbon, allowing all of it to be captured in principle.

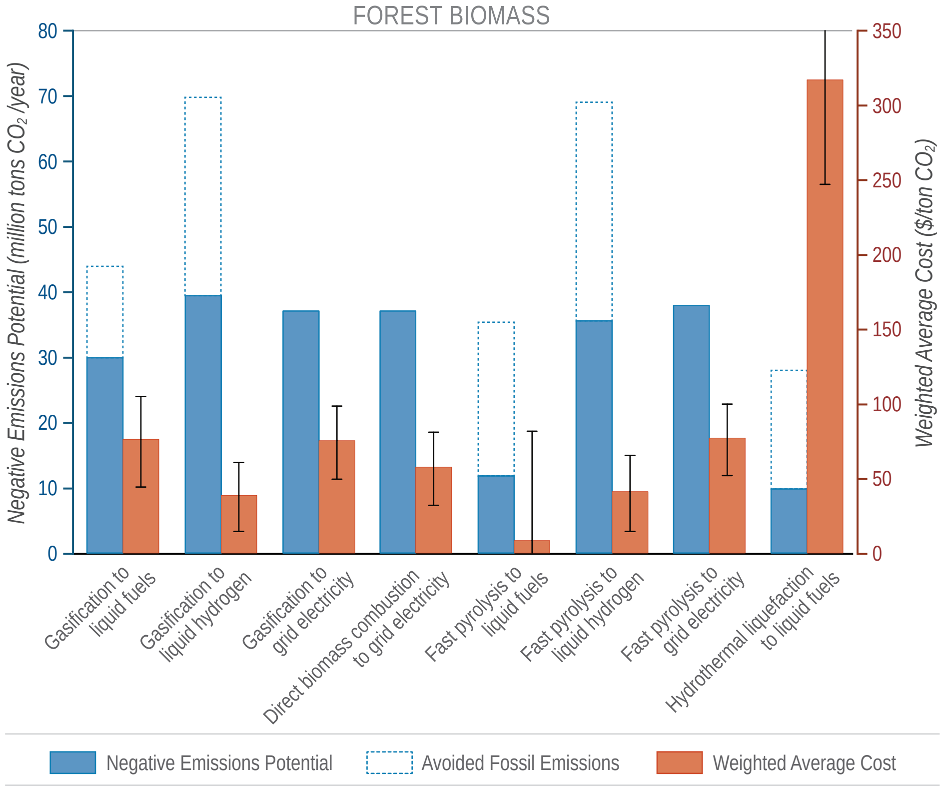


Figure 30. Negative emissions potential, avoided fossil emissions, and weighted average cost to capture CO_2 for forest biomass, calculated for the year 2045. *Note that the weighted average cost does not include the avoided fossil emissions—only the actual negative emissions were used in this calculation, per Equation 2 and Figure 16. Avoided fossil emissions are for 2045, when grid electricity is assumed to have zero carbon intensity. The error bars on the weighted average cost represent the range of costs arising from variation in feedstock collection costs.*

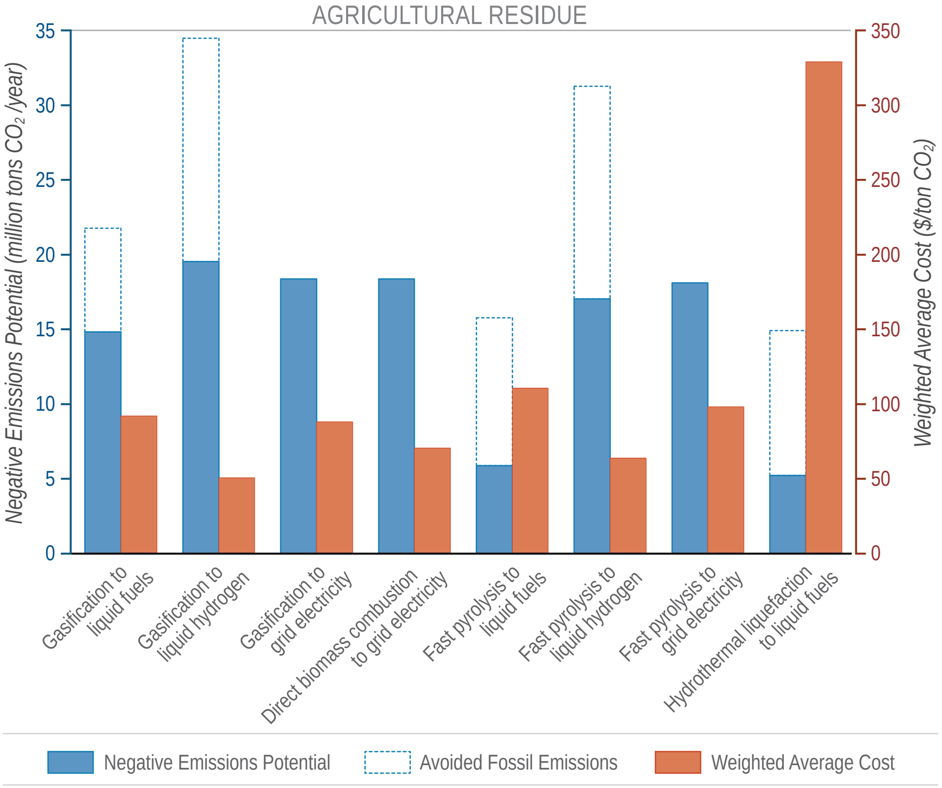


Figure 31. Negative emissions potential, avoided fossil emissions, and weighted average cost to capture CO_2 for agricultural residue, calculated for the year 2045. *Note that the weighted average cost does not include the avoided fossil emissions–only the actual negative emissions were used in this calculation, per Equation 2 and Figure 16. Avoided fossil emissions are for 2045, when grid electricity is assumed to have zero carbon intensity. Note that gasification and fast pyrolysis only consider the dry agricultural residue, whereas hydrothermal liquefaction considers all agricultural residue. We do not present a range of costs for agricultural residue because we assumed a single facility size and collection cost.*

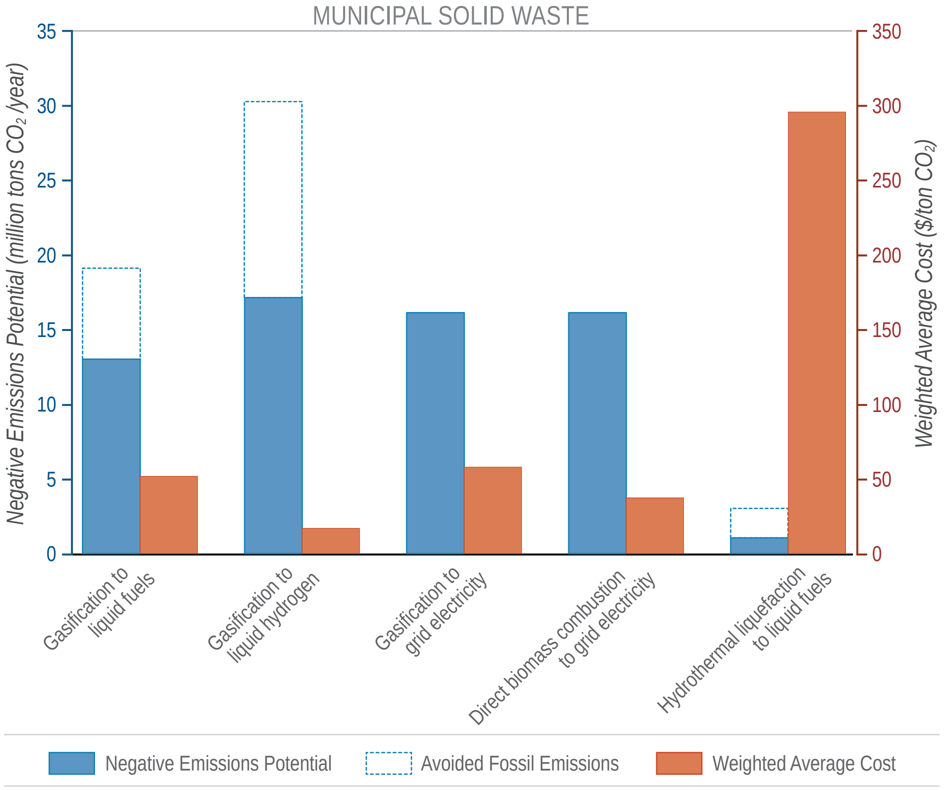


Figure 32. Negative emissions potential, avoided fossil emissions, and estimated cost to capture CO_2 for municipal solid waste, calculated for the year 2045. *Note that the estimated cost does not include the avoided fossil emissions– only the actual negative emissions were used in this calculation, per Equation 2 and Figure 16. Avoided fossil emissions are for 2045, when grid electricity is assumed to have zero carbon intensity. Note that gasification only considers the dry municipal solid waste, whereas hydrothermal liquefaction only considers the wet municipal solid waste; we do not present a range of costs for municipal solid waste because we assumed a single facility size and collection cost.*

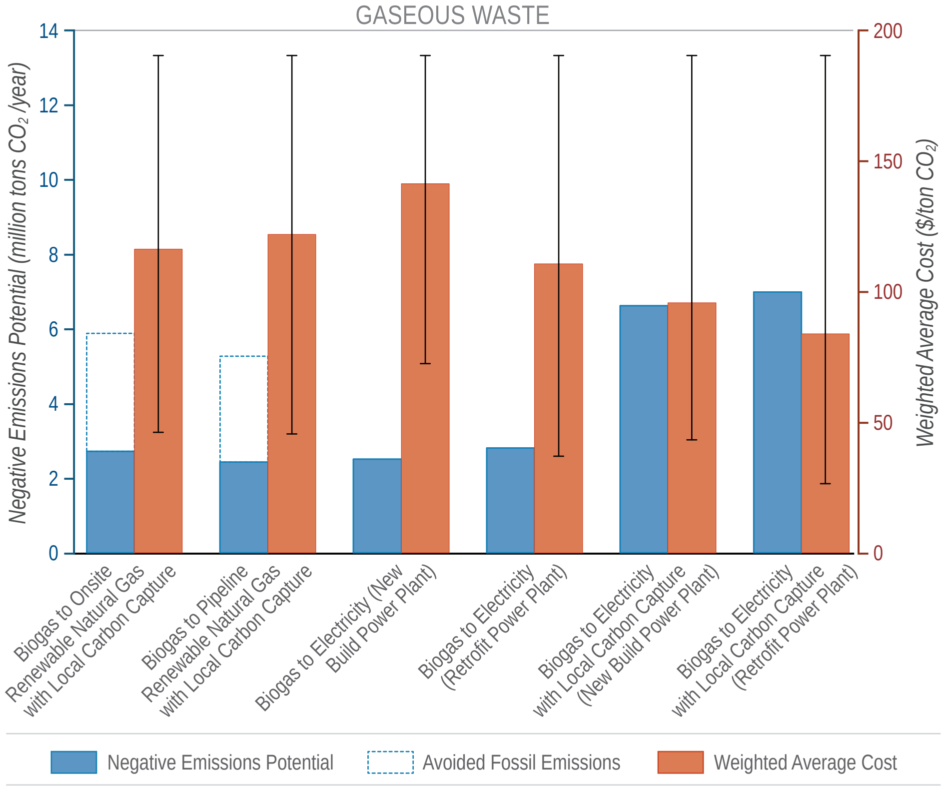


Figure 33. Negative emissions potential, avoided fossil emissions, and weighted average cost to capture CO_2 for gaseous waste, calculated for the year 2045. *Note that the weighted average cost does not include the avoided fossil emissions—only the actual negative emissions were used in this calculation, per Equation 2 and Figure 16. Avoided fossil emissions are for 2045, when grid electricity is assumed to have zero carbon intensity. The phrase "with Local Carbon Capture" indicates carbon capture performed locally at the biogas facility. The scenarios with power plants also include carbon capture at the power plant. The error bars on the weighted average cost represent the range of costs arising from variation in size of existing biogas producing facility where the high end of the bar is set at \$190/ton CO_2 and the low end corresponds to the least expensive facility.*

Sensitivity Analysis for Conversion of Low Moisture Biomass

Across the biomass source categories, low moisture biomass sources make up the majority of the feedstock, leading to these feedstock sources having the highest negative emissions potential. Therefore, we performed an analysis of the sensitivity of the scenarios that consider these sources to various model inputs. In each figure below, one parameter was varied, while the rest were held constant at the common assumption values discussed above. For analyses relating to the sensitivity to product selling price, the biomass cost was assumed to be \$40 per ton biomass, which is the weighted average cost of the forest biomass sources.

The sensitivity to the cost of biomass (Figure 34) is of interest for the discussion of transport costs and logistics in Chapter 7 because it can begin to capture the importance of considering the location of the biomass and siting of biomass conversion facilities. For example, our analysis shows that the cost to capture CO_2 from the production of liquid fuels via fast pyrolysis is highly sensitive to the price of biomass, due to the lower inherent negative emissions potential per ton of biomass in this scenario.

The sensitivity to the value of various products is of interest for policymakers when trying to decide how to incentivize different scenarios. In general, high selling prices for products allow CO_2 capture to be economically viable, even in the absence of any credit for carbon capture. For example, at a wholesale value of \$4.00 per gallon of liquid fuel, fast pyrolysis is by far the most cost-competitive solution for generating CO_2 for geologic storage, while at only \$2.00, it has lost more than \$300 per ton of CO_2 in value (Figure 35). The large sensitivity to product price in this case is due to the relatively low amount of CO_2 produced by the fast pyrolysis to liquid fuels pathway and the large amount of liquid fuel product. The end member cases with a selling price of zero indicate the maximum incentive price for CO_2 capture and geologic storage (not including CO_2 transportation) needed to drive CO_2 capture through various technologies. For example, our analysis indicates that even if hydrogen had no value, at a credit price of \$100 per ton CO_2, gasification to produce compressed hydrogen is still economically viable (Figure 36).

Processes that are more sensitive to variation in product price have higher conversion efficiency of feedstock into fuel. For example, production of electricity from gasification

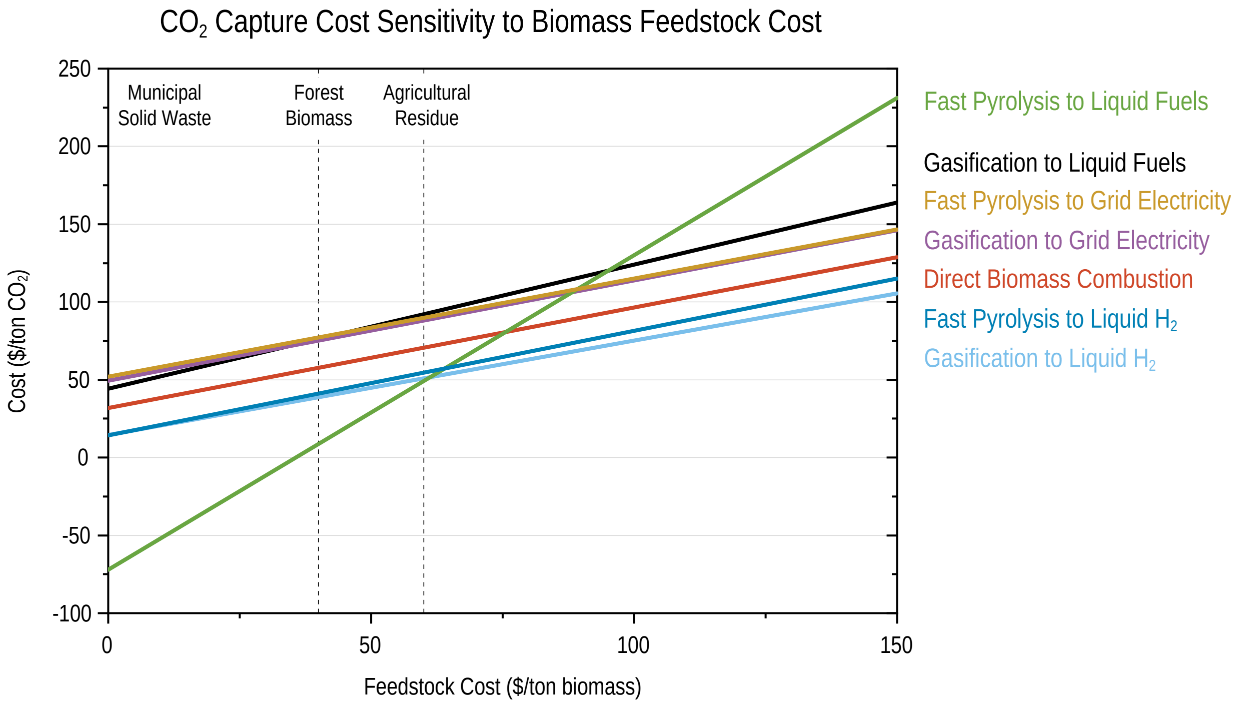


Figure 34. Variation of cost to capture CO₂ from thermochemical conversion processes to the cost of biomass. *Dashed vertical lines indicate weighted average biomass costs used to calculate the cost to capture CO₂ above: Forest Biomass $40 per ton, Agricultural Residue $60 per ton, Municipal Solid Waste $0 per ton. Processes that have a lower inherent negative emissions potential (due to production of carbon-containing fuels) are more sensitive to this parameter.*

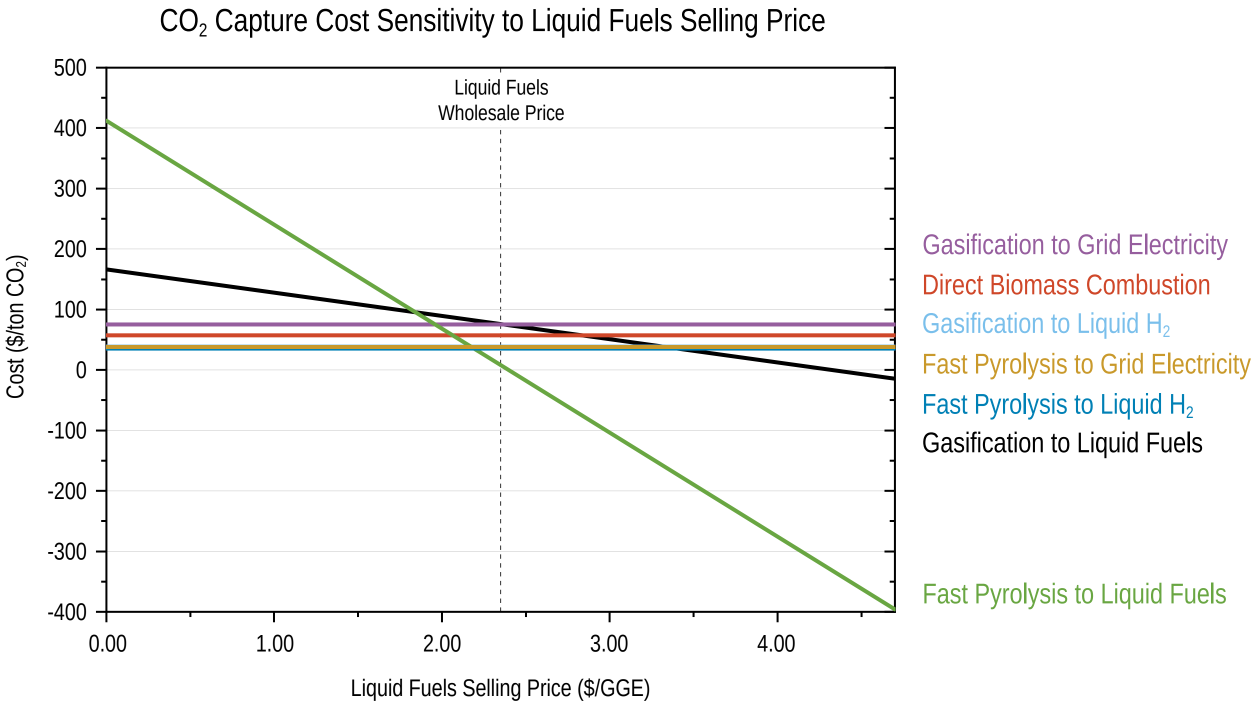


Figure 35. Variation of the cost to capture CO₂ from thermochemical conversion processes to the wholesale price of liquid fuels. *Dashed vertical line indicates the current liquid fuels wholesale price used to calculate the cost to capture CO₂ above: $2.35 per GGE. Production of liquid fuels from fast pyrolysis is more sensitive than gasification to the selling price of liquid fuels due to its higher fuels production efficiency and resulting lower CO₂ negative emissions potential. $/GGE = dollars per gallon gasoline equivalent.*

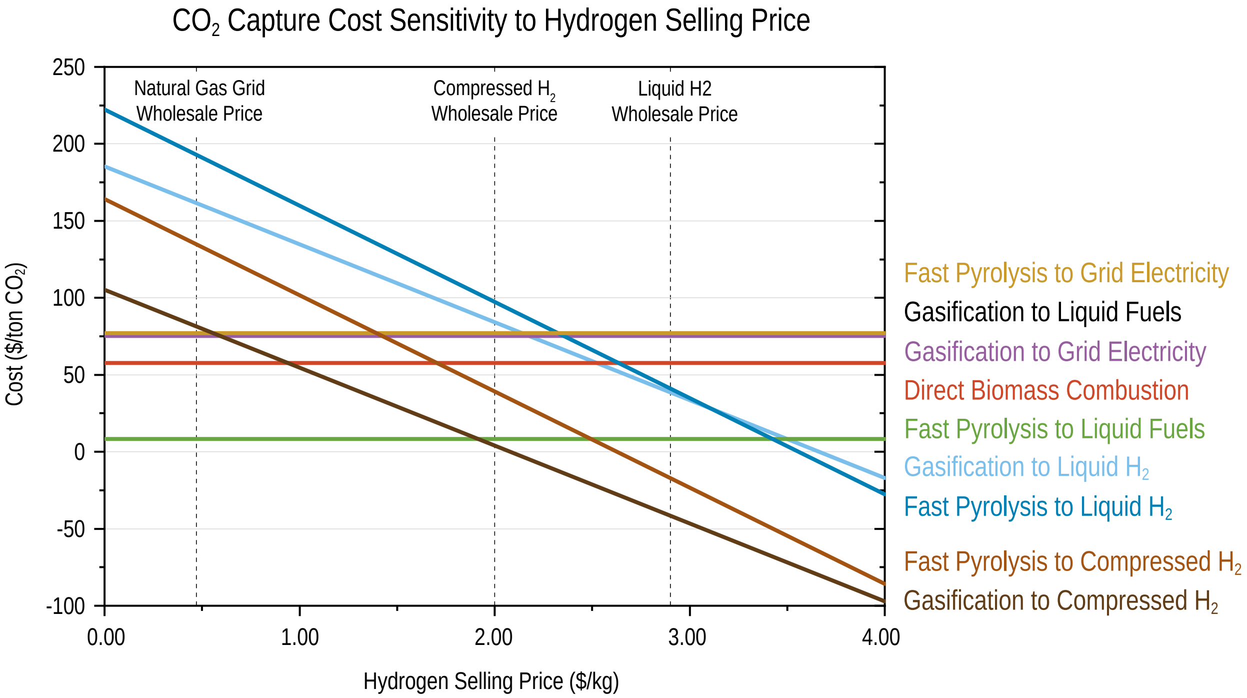


Figure 36. Variation of the cost to capture CO_2 from thermochemical conversion processes to the wholesale price of hydrogen. *Dashed vertical lines indicates the current hydrogen wholesale price used to calculate the cost to capture CO_2 above: Compressed $2.00 per kg, Liquid $2.90 per kg, Natural Gas Grid $0.47 per kg. Gasification to compressed hydrogen is included here as a variant of the gasification to liquid hydrogen scenario, to illustrate the difference in cost due to liquefaction. This scenario only becomes realistic if a hydrogen pipeline is built, the cost of which is not included here, or if hydrogen is blended into the natural gas pipeline and sold at lower value.*

is fairly sensitive to the selling price of electricity (Figure 37), suggesting that mechanisms for stabilization or strong forecasting of this price may be beneficial for industries looking to utilize this technology.

As noted above in the section on production of hydrogen from gasification or fast pyrolysis, we have considered production of liquified hydrogen in these scenarios, because they do not require that a hydrogen pipeline be built. In Figure 36, we include gasification or fast pyrolysis to compressed hydrogen as a variant of this scenario, which becomes realistic if a hydrogen pipeline is built. The cost to capture CO_2 for the gasification to compressed hydrogen scenario is only $4 per ton of CO_2 in this case, assuming a current value of $2.00 per kg of compressed hydrogen; this is compared with $36 per ton of CO_2 in the gasification to liquid hydrogen scenario, assuming a current value of $2.90 per kg of liquid hydrogen. However, the cost of the hydrogen pipeline is not included in this analysis. Alternatively, compressed hydrogen could be blended into the existing natural gas pipeline to allow early implementers of the technology to have an outlet for their hydrogen. Even if this hydrogen is only sold at $0.47 per kg (based on the energy density of hydrogen and the current natural gas citygate price of $4.09 per MBTU), the cost to capture CO_2 is $82 per ton of CO_2, allowing early hydrogen production to generate low cost negative emissions even without a hydrogen pipeline.

Technological Treatment Processes Conclusions

Based on the maximum negative emissions potential for each biomass source, we estimate that, of the maximum 100 million tons of CO_2 contained in the biomass resources in 2045, approximately 83 million tons of CO_2 per year could be reasonably captured for sequestration if gasification is the prioritized technology. If fast pyrolysis is prioritized due to its potential for creating liquid fuels, approximately 42 million tons of CO_2 per year could be reasonably captured for sequestration. The capital cost for the gasification and/or fast pyrolysis facilities in these two scenarios is estimated to be $52 or $29 billion, respectively. Thus, gasification presents the opportunity to sequester larger amounts of biogenic CO_2 than fast pyrolysis, but at higher capital cost.

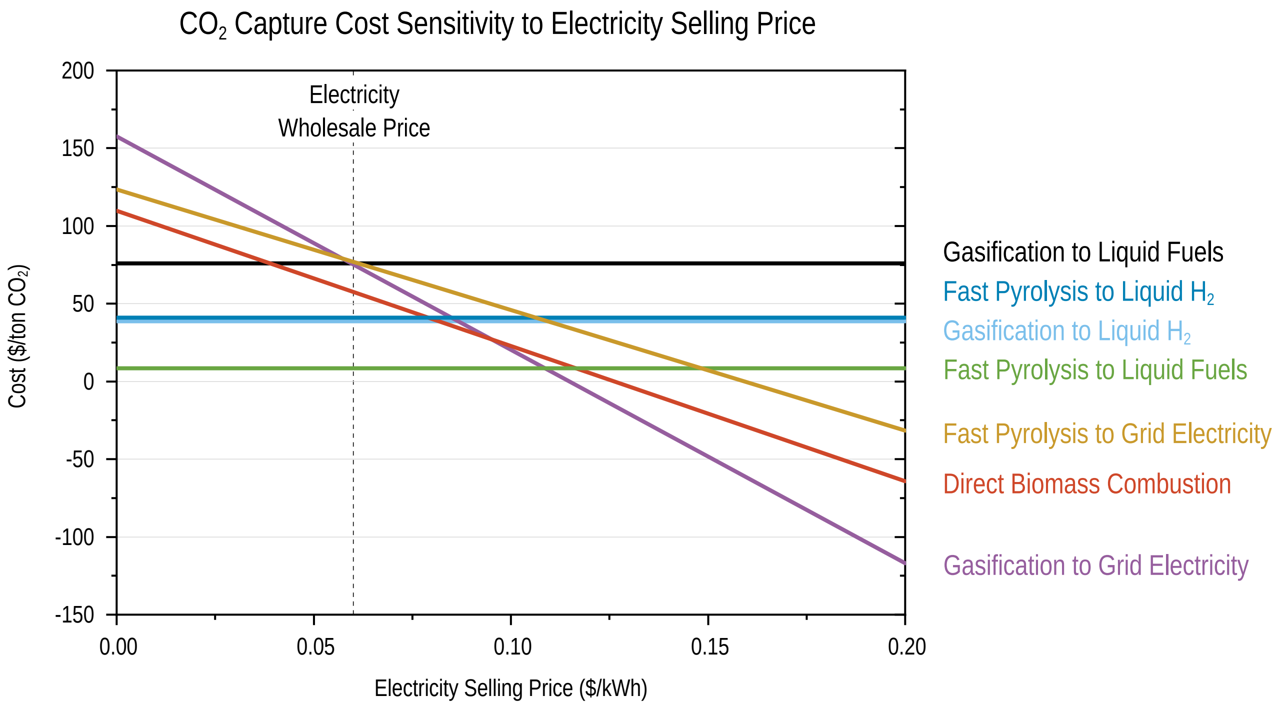


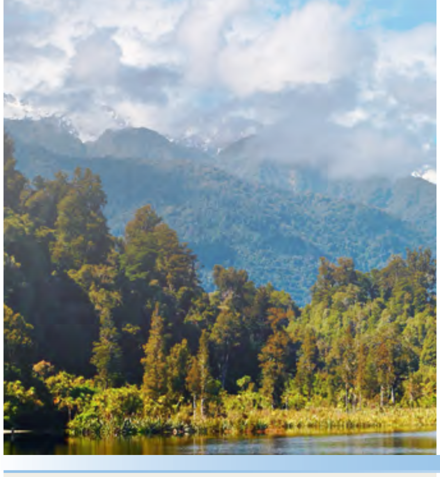
Figure 37. Variation of the cost to capture CO_2 from tthermochemical conversion processes to the wholesale price of electricity. *Dashed vertical line indicates the current electricity wholesale price used to calculate the cost to capture CO_2 above: $0.06 per kilowatt-hour. Production of electricity from gasification is more sensitive than fast pyrolysis or direct combustion due to its higher electricity production efficiency.*

This analysis of technology options for various biomass sources allows us to downselect several viable options for consideration on the basis of cost and amount of CO_2 when we include transportation of biomass and CO_2. In particular, for low moisture biomass feedstocks, gasification to hydrogen appears to be a relatively low-cost option for generating the maximum amount of negative emissions while also being aligned with other programs and legislation within the state. We will also consider fast pyrolysis to liquid fuels, due to its low forecasted cost after technology learning (Chapter 8) and strong sensitivity to the cost of biomass and the selling price of liquid fuels, and direct combustion of biomass to produce electricity, due to it being the most established commercial technology and the potential for constructing small facilities close to the biomass sources. Our analysis suggests that hydrothermal liquefaction is the highest cost technology per ton of CO_2 for conversion of forest biomass and agricultural residues, in addition to municipal solid and green waste. Therefore, we did not further consider hydrothermal liquefaction as a treatment for these feedstocks and chose instead to assume green waste is treated by composting, as described in Chapter 2. For biogas utilization, centralized processing is more cost effective than distributed processing due to the difficulty of performing CO_2 capture at very small scale. Therefore, the most cost-effective scenarios involve processing biogas at only largest scale sites and aggregating the biogas from smaller sites.

In Chapter 7, the costs for capturing CO_2 from gasification, pyrolysis, and biogas utilization will be revisited in light of transportation costs, the location of the biomass, and the location of the geologic storage sites, to devise a transportation network for biomass and CO_2 around the state, and total costs of negative emissions technology pathways from biomass source to geologic storage.

CHAPTER 5

Direct Air Capture



SUMMARY

The third pillar in our approach to negative emissions is direct air capture: removing CO_2 from the air using machines built for that purpose. It is more expensive than most negative emissions options for California but has a nearly unlimited technical capacity. The first step of the direct air capture process is to absorb CO_2 into a solvent or adsorb CO_2 onto a solid sorbent material. The second step is to release the CO_2 from the capture agent to produce a high-purity stream of CO_2 for geologic storage. The process is energy intensive, requiring 180 to 310 megawatts of power for a CO_2 capture rate of 1 million tons per year, which leads to extensive land use requirements when powered by solar or wind energy. For this reason, we focus our analysis on two types of direct air capture that appear most suited to California: solvent-based systems powered by natural gas with CO_2 capture, and solid sorbent systems powered by geothermal energy. We also assess the potential of industrial waste heat to power direct air capture, but because these industrial heat systems do not meet our definition of negative emissions, we don't include them in later chapters.

Key Findings

Direct air capture with geologic storage appears to be technically feasible in California. Although land use is a significant concern for some versions of the technology, geothermal and natural gas-based facilities are compact and effective. The existing and potential geothermal energy in California could power as much as 11 million tons of sorbent-based direct air capture per year from new facilities, and 5 million from using existing geothermal now used to generate electricity. Capture potential by solvent-based systems powered by natural gas is essentially unlimited, provided that the fugitive emissions from natural gas transmission are minimized. The solvent systems can be constructed close to CO_2 storage sites (as described in Chapter 6), minimizing transport costs, while the geothermal facilities will require some infrastructure to move captured CO_2 to these sites.

We estimate the near-term costs of direct air capture to be roughly $266 per ton CO_2 removed for sorbent-based, geothermal plants and $230 per ton CO_2 removed for solvent-based natural gas plants. These costs will come down by around 20-30% in the near future as new generations of plants are built and improved. We estimate how the costs will change by 2045 in Chapter 8.

Scope of Chapter

Technologies that remove CO_2 from the air directly by industrial means. We assess versions of the technology powered by:

- natural gas with CO_2 capture
- wind
- solar
- geothermal
- industrial waste heat

We compare these options on the basis of land use, cost, and potential capacity in California, and then identify the most promising technologies. These costs and technology choices are adopted later in the report.

Introduction

Direct air capture involves using machines to capture and remove CO_2 from the atmosphere. The National Academies have recently reviewed the status of costs of direct air capture technologies [187]. Three leading global companies operate demonstration-scale plants: Carbon Engineering has a demonstration plant in Canada [188]; Climeworks has 14 small demonstration plants, mainly in Europe [189], [190] and Global Thermostat are finalizing a demonstration plant in the United States [191], [192].

The first step of the direct air capture processes is to absorb CO_2 into a solvent or adsorb CO_2 onto a solid material. The second step of the process is to break the carbamate or carbonate bond that links the CO_2 to the capture agent, producing a high-purity stream of CO_2 and allowing to regenerate the capture agent for reuse. The first step is generally a spontaneous process; however, extracting the CO_2 from the capture agent is an energy intensive endothermic reaction that covers about 80% of the energy requirement for a direct air capture plant. The remaining 20% of the energy requirement is electricity [187]. Carbon Engineering's solvent process uses a calcining step requiring temperatures of up to 900°C and depending on the extent of internal thermal process optimization, corresponds to an energy input of between 5.25 to 10.7 gigajoules per ton of CO_2 to produce high-purity CO_2. Climeworks's and Global Thermostat's processes capture the CO_2 with an amine-based solid material, and regeneration of that requires about 100°C heating and between 3.4 to 5.8 gigajoules per ton of CO_2 [187]. The primary differences between the two types of approaches are the temperature of the recovery phase and the breakdown of the components associated with their capital expense. Carbon Engineering's 900°C requirement currently restricts them to using natural gas as a heat source, capturing the combustion CO_2 along as well as atmospheric CO_2 (very little CO_2 is emitted by the use of natural gas, and overall the process results in a large net decrease in the CO_2 in the atmosphere). At the 100°C regeneration temperature of solid sorbent approaches, they are more amenable to coupling with renewable energy sources.

In this report, we consider three approaches to direct air capture using these existing technologies that we believe are well-suited to California's needs:

1) Utilizing natural gas for heat and electricity needs; conducted adjacent to an underground storage site to minimize transport of CO_2 (Carbon Engineering's approach)
2) Using renewable energy; located adjacent to a storage site (Climeworks' and Global Thermostat's approach)
3) Using geothermal heat; located adjacent to geothermal sites (Climeworks' and Global Thermostat's approach)

Land Area for Direct Air Capture

Although the cost of direct air capture receives the most attention, the required land area may be significant as well, which heavily influenced our choice of scenarios appropriate for California. A plant designed to remove 1 million tons of CO_2 per year from the atmosphere would require 7 km² of land area [193] for the solvent-based direct air capture plant alone, and 2 km² of land area for the solid sorbent [194] approach with most of the area represented by the indirect use space between air contactors [187, p. 226]. Additional land area considerations include the energy plant used to power the direct air capture facility. For example, the electric component of each direct air capture approach can be entirely powered from renewable electricity coupled with battery storage. Additionally, solar (photovoltaic) may be used to provide heat for the low-temperature (solid sorbent) approach, either through resistive heating or concentrating solar power. We considered the land area requirements for three different energy scenarios: natural gas power plant, solar energy, and wind energy (Table 26). The California generation weighted land area footprints of these energy sources, assuming a solar and wind capacity factor of 28%, are roughly:

- Natural Gas: 1,400 m²/MW (0.34 acres per MW) [195]
- Solar (photovoltaic) Energy: 116,550 m²/MW (28.8 acres per MW) [195]
- Wind Energy: 1.19 km² /MW (294 ± 198 acres per MW) (total facility footprint) [196])

Assuming an electric demand of 0.83 and 1.5 gigajoules per ton of CO_2, thermal demands of 5.8 gigajoules per ton of CO_2 and 9.2 gigajoules per ton of CO_2 for the solid sorbent and solvent approaches, respectively [187], [188], [194], and a utilization factor of 90%, the energy requirements come out to 182 and 305 megawatts for the solid sorbent and solvent approaches, respectively. The corresponding land area footprints for the energy and direct air capture joint facilities are shown in Table 24. Note that if the electric and thermal energy demands are at the higher end of the ranges provided earlier, the power and thus land requirements will increase. In addition, due to the early technological readiness of electric kiln technology today, natural gas was assumed

Table 24. *Land area footprints for direct air capture and energy joint facilities capturing 1 million tons of CO_2 per year. In the case of the solvents, only solar and wind are powering the electric component of the energy with natural gas powering the thermal component.*

	Natural Gas		Solar		Wind	
	Sorb.	Solv.	Sorb.	Solv. (NG)	Sorb.	Solv. (NG)
Energy Footprint [km²]	0.26	0.43	21	5 (0.37)	217	51 (0.37)
Direct Air Capture Footprint [km²]	2	7	2	7	2	7
Total Land Area Footprint [km²]	2.3	7.4	23	12.4	250	58.4

km² = square kilometers, NG = natural gas

to supply the thermal energy required in the case of the oxy-fired kiln for the liquid solvent cases. This is why the land area for the solid sorbent case is so much larger than for the solvent case when assuming low-carbon energy sources such as solar and wind. Advanced solvent approaches that would allow for coupling to non-fossil-based energy resources would ultimately have a greater impact in terms of net carbon removed from air.

We have not considered the obvious system integration options of co-locating wind, solar, and direct air capture facilities to minimize the footprints. However, the very large required energy footprints led us to consider more focused energy resources. If we need 50 million tons per year of direct air capture in California, it does not seem realistic to assume that 50 x 23 = 1150 km² of land would be dedicated to that purpose when smaller options are available. This is compounded by the problem that large areas of land are unlikely to be near good geologic storage sites. While the solvent system coupled with solar to power electric components has a smaller footprint per million tons of CO_2 captured, the net removed footprint would be substantially larger unless the CO_2 generated from natural gas consumption were captured and subsequently stored. We therefore focused our analysis on geothermal heat and natural gas with full re-capture and did not consider solar- or wind-powered systems.

Cost Considerations

Costs for direct air capture are significantly larger than for the biomass-based approaches discussed previously. Some studies estimate that the long-term cost of direct air capture could be as low as \$100 per ton of CO_2 removed [187], [189], [190], [197], [198], although the cost today is roughly \$600 per ton of CO_2 removed [190], [199]. We expect that ultimate costs may be as low as \$150–300 per ton of CO_2 removed for direct air capture plants paired with low-carbon or waste sources of energy such as nuclear, geothermal, and locally-produced gas [200] (see Chapter 8 on learning).

Currently a direct air capture plant capable of removing 100 kilotons of CO_2 per year and paired with geothermal energy requires a capital intensity of \$680 to \$750 per ton of CO_2, of which 81–89% is devoted to the contactor (sorbent and monolith), the rest being split between the fan, vacuum pump, heat exchanger, and compressor. Assuming a plant lifetime of 10 years and a discount rate of 12.5%, the levelized cost of capital breaks down to \$135 to \$147 per ton of CO_2 per year. Operating and maintenance add an additional \$64 to \$103 per ton of CO_2 per year, depending on the need for external consumables like steam or electricity. Generally, fan and vacuum power cost roughly \$28 per ton of CO_2; maintenance is assumed as 3% of the total capital investment, and labor is estimated as 30% of the maintenance cost [200].

For new, unexploited geothermal resources, the cost of well construction, operations, and maintenance must be included in the above estimates. This results in an incremental cost of capture of \$60 per ton of CO_2, of which \$50 per ton of CO_2 is assigned to the capital-intensive task of well construction.

Alternatively, a direct air capture plant based on the solvent separation approach as outlined in Keith et al. [188] has a capital intensity of \$1,146 per ton of CO_2 to capture 980 kilotons of CO_2 per year. Like the sorbent case, the contactor investment dominates but at a much smaller share of the total (30%), where the pellet reactor, calciner, power island, and other equipment make up the balance. One key feature of the Keith design is a PVC-based (polyvinyl chloride-based) packing material which is projected to cost 1/6th that of conventional metallic and ceramic packing materials [187]. Uncertainty remains regarding the durability of PVC-based materials in the caustic solvent environment over time; thus, more frequent packing material exchange and any operational loss of availability would counter material cost savings. Assuming no loss in stability or performance versus traditional packing, a 25-year plant lifetime, capital recovery of 12.5% and availability of 90%, the total capital investment is amortized to $159 per ton of CO_2 per year. Operating costs add $73 per ton of CO_2 per year, where $31 is attributed to consumable natural gas and the remaining $42 to non-energy operations and maintenance.

Carbon Engineering (Solvent) Approach

The full-scale Carbon Engineering plant powered by natural gas would recover 1 million tons of CO_2 per year from the atmosphere. We envision locating plants near natural gas production sites to reduce emissions from natural gas handling operations, but we have not attempted to quantify those emissions. Carbon Engineering has provided an extensive description of this reference plant in a recent publication [188].

We assume the baseline case in [188] where thermal and electricity needs for direct air capture are met through combustion of natural gas with the inclusion of conventional carbon capture. Ninety percent of the CO_2 is captured from the gas turbine exhaust using a counter-flow gas-liquid column 12 × 7.5 meters (height × diameter). The outlet of the absorber is ducted to the air contactor where an additional 75% of the remaining CO_2 is captured. At full capacity, the plant is designed to remove 0.98 million tons of CO_2 per year from the air, but ultimately produces 1.46 tons of CO_2 per year of CO_2 compressed to 15 megapascals going to storage. The additional 0.48 million tons of CO_2 per year is produced on-site via combustion of natural gas to meet all the direct air capture plant's thermal and electrical requirements.

The solvent-based design has a capital intensity of $1,146 per ton of CO_2 per year. This includes the air contactor ($212.2 million), the pellet reactor ($130.7 million), and the calciner/slaker ($77.7 million), with the balance devoted to compression, the air separation unit, the power block, other equipment, as well as indirect and non-field costs. At a 12.5% recovery factor, Keith at al., (2018) [188] estimates a cost of **$232 per ton of CO_2 net removed** from the atmosphere for the base case described above. It is important to note that the authors estimate that the capital cost of the system has an uncertainty of roughly + 50%.

Detailed Breakdown of the Cost Estimate: The levelized cost of CO_2 captured from the atmosphere was calculated as the sum of levelized capital cost, non-fuel operation and management, and energy costs. The levelized capital cost is (CI × CRF)/U, such that "CI" is the capital intensity or capital cost per unit capacity, e.g., dollar cost per ton of CO_2 per year. The capital recovery factor is a levelized annual charge on capital divided by the overnight capital cost. A capital recovery factor of 12.5% was in [188]. Utilization was assumed to be 90%.

To determine the energy costs, a price of $3.5 per gigajoule was assumed for natural gas with an input of 8.81 gigajoule per ton of CO_2.

Levelized capital cost of net removed CO_2 =
($1146 × 0.125)/ 0.9 = $159

Non-fuel operation and management = $42

Energy costs =
($8.81 gigajoule/ ton of CO_2) × ($3.5/ gigajoule) = $31

Total levelized cost of net removed CO_2 =
$159 + $31 + $42 = **$232** [2, Config A Table 2]

No external electricity is required to operate this configuration. Note that the authors also calculated the costs for the same system with a lower capital recovery factor of 7.5%, yielding $168 per ton removed, and highlighting the importance of capital cost in the long-term financing of this kind of project. We use the 12.5% factor for consistency with our other costs.

Solid Sorbent Approaches

Cost estimates for solid sorbent approaches are available in the National Academies report [187]. We have considered the option of using California's geothermal resources to supply some or all of the regeneration heat in these systems, generating lower overall costs and most importantly, reducing the footprint of the operation. We are able to provide costs based on existing geothermal plants in California, but much more geothermal energy is available than is currently tapped for electricity generation. To account for future exploitation of geothermal resources for the purposes of direct air capture, costs associated with well drilling, construction, operation, and maintenance are considered separately.

The highest geothermal temperatures are found in the vicinity of the Salton Sea in Southern California. Another hotspot is located north of San Francisco in the Geysers area, and there are wells with temperatures slightly above 100°C between San Francisco and Los Angeles. There are also local hotspots located northeast of Redding, California and near Mammoth Lake, California (Figure 38). As the design of direct air capture plants provides flexibility in both placement and size, appropriately sized direct air capture plants could also be placed where geothermal fluids or warm water associated with current oil and gas production are located.

Below, we explore two possibilities for making use of geothermal energy. Either the geothermal fluid has sufficient temperature (100°C or higher) and can be used directly, or the geothermal fluid has a temperature between 60°C and 100°C and has to be upgraded to 100°C using a heat pump before solid sorbent regeneration. Geofluid data cover a broad range of temperatures and fluid flows, which are used to determine the size of the direct air capture plant required to capture a given amount of CO_2 from the atmosphere.

Geothermal Energy

Multiple databases provide data about the geothermal resource available in California. Most of the databases provide the temperature and the depth of the geothermal resource, but very few of them have fluid flow data. Fluid flow data are necessary to calculate the potential CO_2 captured, and envision the size of the direct air capture plant that can be paired with that resource to optimize the use of the geothermal resource for CO_2 capture. The databases used here, including source and data available, are listed in Table 25 and represented on Figure 38 From the databases listed in Table 25, we created two new datasets. They both gather geothermal fluid data with a temperature above or equal to 100°C, the first one with fluid flow information, and the

Table 25. *List of the databases used for geothermal data in this report. The data were sorted into three categories: geothermal fluids with temperatures over 100°C and with or without fluid flow information, and geothermal fluids with temperatures between 60 and 100°C with fluid flow information. Data in brackets are the number of entries effectively used in the dataset when data were discarded to avoid redundancies. GDR: Geothermal Data Repository, OIT: Oregon Institute of Technology, NGDS: National Geothermal Data System, AASG: Association of American State Geologists, SMU: Southern Methodist University Geothermal Laboratory, USGS: United States Geological Survey.*

Database name	Source	Reference	Number of sites		
			Fluid flows		Fluid flow data lacking
			T>100°Cr	60<T(°C)<100	T>100°C
AASG geothermal boreholes	AASG	[201]	-	-	509 (390)
AASG/SMU wells	AASG & SMU	[201]	-	-	291 (2)
CA thermal springs	NGDS	[202]	1	-	3 (0)
Coastal plains, delineated areas, and isolated systems	Williams et al., 2008 [203]	[201]	-	-	31 (0)
Core template heat flow materialized		[204]	-	-	46 (36)
Direct use geothermal	SMU	[205]–[207]	1	15	-
OIT co-located	NREL & GDR	[201]	17 (14)	-	3 (3)
OIT wells and springs	OIT	[201]	9	-	25 (1)
SMU geothermal boreholes	OIT	[201]	-	-	34 (34)
USGS identified delineated-area geothermal system	SMU	[201]	-	-	5 (0)
USGS isolated geothermal systems	USGS	[201]	-	-	12 (12)
Western geothermal area database	USGS	[201]	-	-	32 (1)

second one without fluid flow information, outlining the location where heat from geothermal could be used directly to regeneration sorbents for direct air capture.

Figure 38 summarizes geothermal resources in California. Geothermal fluid data points with fluid flow information are located in the Salton Sea area, Geysers area, northeast of Redding, and near Mammoth Lake. However, some data points within these regions have no specified fluid flow rates. All these data points are associated with favorable geothermal environments with high geothermal heat flows [203]. In the vicinity of the Salton Sea and the Geysers, temperatures over 100°C are found in less than 500 meters depth, and northeast of Redding, temperatures over 100°C are found at a depth of 1,000 to 2,000 meters [201]. The rest of the datapoints with no flow data are located between San Francisco and Los Angeles in areas with a high-density of oil and gas wells [208]. An additional source that could merit future investigation includes the large amounts of water associated with current oil and gas production, shown as black dots in Figure 38.

Calculation of the CO_2 Uptake Using Geothermal Fluid Flows

The fluid flow data are needed in order to know the quantity of sorbent that can be regenerated and thus to calculate the size of the direct air capture plant paired with geothermal. We calculated the quantity of CO_2 that can be captured at a given geothermal source using our fluid flow database (Appendix C), the parameters specified in Table 26, and the following equation:

Equation 3. *CO_2 Potential Uptake*

$$\alpha_{DAC-geo}\left(\frac{tCO_2}{yr}\right) = (T_{wi} - T_{wo}) \times \frac{C_w \times F_w \times n \times \rho_w \times 60 \times 24 \times 365}{E_{req}} \times \eta$$

In the heat pump scenario, a ratio of 1:3 electrical input to thermal output was assumed [209].

Figure 39 and Table 27 provide details about number of direct air capture facilities paired with geothermal and CO_2 uptake potential. Direct air capture plants associated with geothermal resources over 100°C have the potential to capture 4,582 kilotons of CO_2 in California. In addition, the

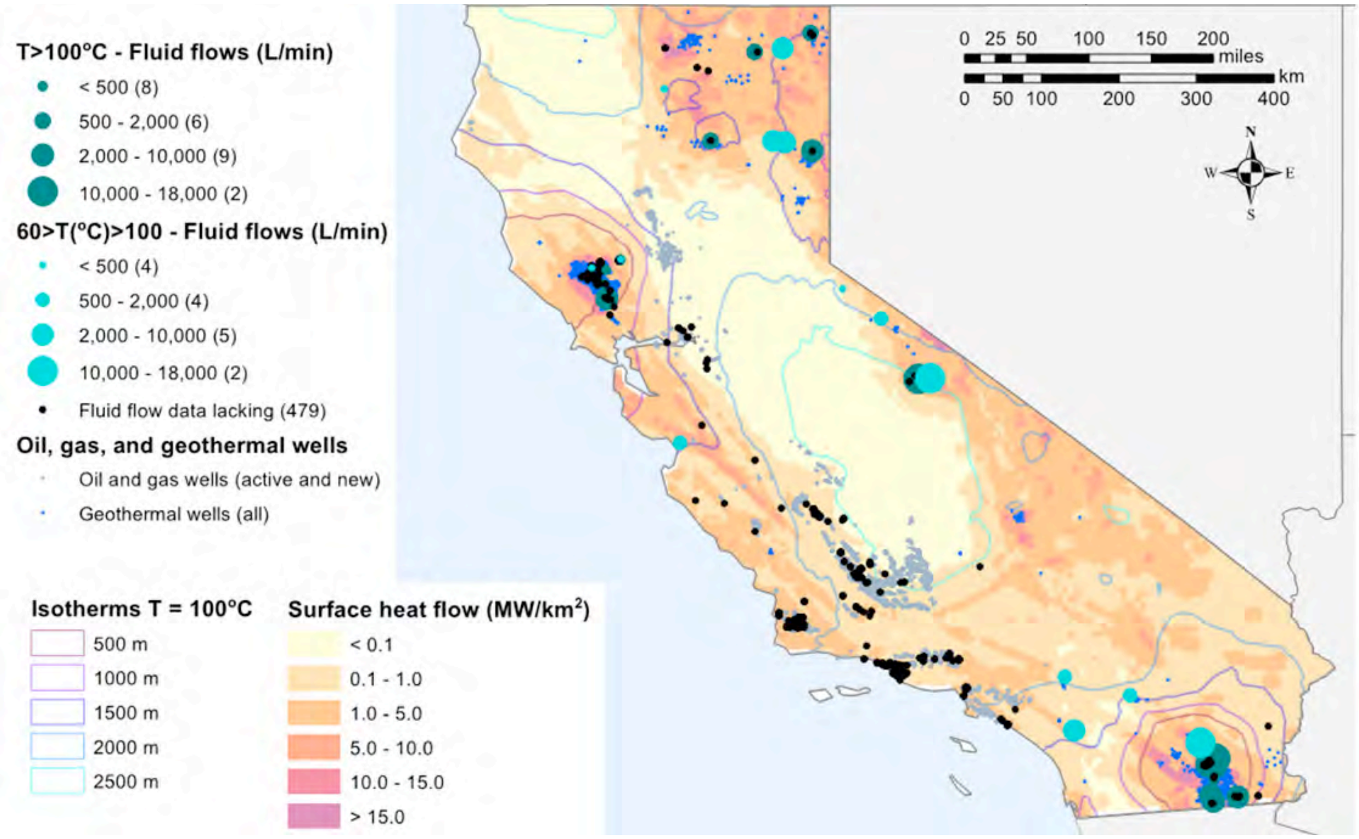


Figure 38. *Geothermal fluid data over 100°C with and without fluid flow information and between 60°C and 100°C with fluid flow information in California [NREL Geothermal Prospector; CDOGGR Arizona Geological Survey, 2013; Williams et al., 2008; SMUGL, 2014; Snyder et al., 2017; NREL, 2017]. The surface heat flow is provided by the United States Geological Survey [Williams et al., 2008], the temperature at depth by the NREL [NREL Geothermal Prospector], the oil, gas, and geothermal wells with no temperature or flow data by the California Department of Conservation [DOGGR, 2019], [DOGGR, 2016]*

Table 26. *Parameters used for the calculation of CO_2 potential uptake by a direct air capture plant using geothermal heat for sorbent regeneration*

Parameter	Description	Nominal value	Units
T_{wi}	Temperature of water before sorbent regeneration	Site-specific	°C
T_{wo}	Temperature of water after sorbent regeneration	70	°C
C_w	Specific heat of water	4.186	J/g/°C
F_w	Geothermal fluid flow	Site-specific	L/min
E_{req}	Long term energy requirement	1600	kWh/tCO2
n	Conversion coefficient from J to kWh	2.7778x10-7	kWh/J
ρ_w	Density of water	1000	g/L
η	Heat efficiency	0.85	-

J = Joule, kWH = kilowatt hour, g = grams, L = liter

association of lower temperature geothermal (60 < T(°C) < 100), heat pumps, and direct air capture could capture 498 kilotons of CO_2 per year, adding up to a total of roughly 5 million tons of CO_2 per year. Ten direct air capture plants—8 in the Salton Sea area and 2 in the Mammoth Lake area—would have the capacity to capture more than 100 kilotons of CO_2 each per year, with a total capture potential of 4,283 kilotons of CO_2 per year or 84% of the total capture potential in California from existing geothermal sources and wells. This potential could be greatly improved if more wells with a temperature over 100°C, and high flow rates are identified. The Salton Sea area is particularly interesting in this regard, as there is at least two more gigawatts of untapped geothermal resource there [210]. The capacity of the direct air capture plants increases linearly with increasing fluid temperature or increasing fluid flow. To capture over 100 kilotons of CO_2 per year, flow rates over 10,300 and 2,400 liters per minute are necessary at fluid temperature of 100 and 200°C, respectively.

We identified 11 existing wells in the Salton Sea region with temperatures above 100°C that have fluid flow rates between 500 and 18,000 liters per minute, and carbon capture potentials between 11 and 1,625 kilotons of CO_2 per year, totaling to 4,581 kilotons of CO_2 per year. In addition, two other wells have temperatures between 60 and 100°C and flow rates of 3,350 and 10,108 liters per minute, and could capture 33 and 98 kilotons of CO_2 per year, adding up to a total capture potential of 3,828 kilotons of CO_2 per year in the Salton Sea area on existing geothermal sources and wells.

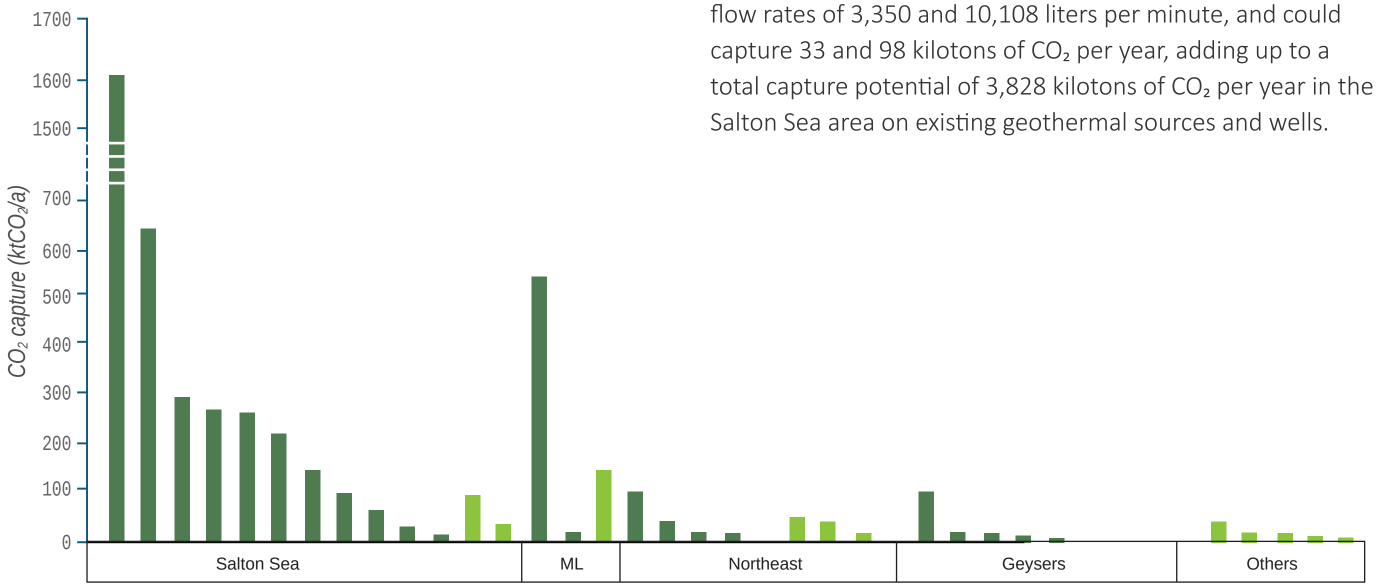


Figure 39. *Direct air capture potential of existing geothermal sources and wells in California by location. (ML = Mammoth Lake)*

Table 27. *Details of the number of direct air capture plants and their capture potential by area.*

	T > 100°C		60 < T(°C) < 100		Total capture potential [$ktCO_2$/yr]	Total number of plants capturing > 100 $ktCO_2$/yr
	Number of plants	Capture potential [$ktCO_2$/yr]	Number of plants	Capture potential [$ktCO_2$/yr]		
Salton Sea	11	3,697	2	131	3,828	8
Mammoth Lake	2	565	1	148	684	2
Northeast	5	178	4	120	181	0
Geysers	7	142	2	3	290	0
Others	0	0	6	96	96	0
Total	25	4,582	15	498	5,080	10

$ktCO_2$/yr = kilotons of CO_2 per year

The locations and sizing of the direct air capture plants associated with geothermal resources above 60°C are shown in Table 27 along with the locations for water temperatures above 100°C but for which no fluid flow data were available, and the carbon capture potential could not be estimated. Of particular interest is the untapped geothermal potential in the Salton Sea region, currently estimated to be 2 gigawatts of thermal energy [191]. This energy might be most appropriately used for the solid sorbent approach. Taking the average electric and thermal energy (0.83 + 4.1 gigajoules per ton of CO_2) – combined, the potential direct air capture from 2 gigawatts translates to roughly to 12.8 million tons of CO_2 per year direct air capture potential. Assuming a 90% utilization factor, roughly 11 million tons of CO_2 of new capture capacity could be obtained from this energy source. Thus, California's potential direct air capture powered by geothermal energy is as great as 16 million tons per year. This amount of direct air capture must be tempered by the current or future use of that energy to make carbon free electricity, and the need to transport the captured CO_2 to an appropriate permanent storage site, which are not well aligned with the geothermal resource.

Calculation of the CO_2 Uptake Using Industrial Waste Heat

Industrial operations in California could also supply heat for direct air capture operations. These heat sources are generally fossil-fueled, so any air capture would not represent negative emissions, but rather reductions in residual emissions. However, we considered whether those sources would make a significant impact in California's greenhouse gas emissions.

The amount of waste heat from industrial emission sources in California was used to determine the approximate size of a direct air capture facility (powered solely by using the waste heat from these industrial emitters). The emissions information for stationary combustion at refineries, mineral production plants, and metal production units was obtained via the Environmental Protection Agency Flight database [211]. From here, the stationary combustion emissions were converted to determine the power production (megawatt) from each facility assuming that 1 megawatt generated is equivalent to 3,850 tons of CO_2 emitted. These facilities were ordered by the amount of power generation occurring onsite. These were then correlated to the available waste heat data from the table Waste Heat to Combined Heat and Power Technical Potential (Sub-Table 1.1) presented in the Combined Heat and Power (CHP) Technical Potential in the United States report by the US DOE in 2018 [212]. Here, the breakdown of facilities by the size of power production is given, as well as the total waste heat available for facilities in that power production range. The amount of waste heat at each facility was calculated by dividing the industrial CO_2 emitters in California into the same power production categories. From here, the total available waste heat for the power production category from the DOE report was split amongst the qualifying facilities based on that facility's contribution to the overall power production in that range (i.e., the weighted average of power production for each category).

To determine the size of the direct air capture facility associated with these waste heat values, the average electricity (0.83 gigajoules per ton of CO_2) and thermal (4.1 gigajoules per ton of CO_2) from the National Academies of Sciences Engineering and Medicine 2019 solid sorbent analysis were summed to give an overall energy requirement of 4.9 gigajoules per ton of CO_2 [187]. The size of direct air capture plant was then determined using the calculated waste heat potential at each industrial emissions source [187].

It is important to note that some of these facilities, specifically those associated with mineral production, produce more waste heat than what is attributed to stationary combustion alone. This is due to high temperature process streams that can also be integrated as waste heat for power production. Additionally, the number of existing industrial facilities is greater than the number of facilities accounted for in the United States Department of Energy report. All of these facilities had a smaller number of stationary combustion emissions (<40 kilotons of CO_2). In these cases, the reported waste heat potential was divided amongst the facilities having larger amounts of stationary combustion. This includes 1 refinery, 1 cement production facility, and 5 metals production facilities. For each industry sector, details of the emissions, the available waste heat, the size of the direct air capture plant and the CO_2 net removed are provided in Table 28.

The direct air capture paired with industrial waste heat sources could remove 2.3 million tons of CO_2 per year from the atmosphere, or 0.6% of total greenhouse gas emissions in California. This amount is distributed over 39 facilities, making transport challenging, and is too small to have a significant impact on our overall calculations, so we have not evaluated the associated transport and storage options.

Figure 41 shows the capital and operating cost breakdown for three configurations of solid-sorbent systems that we evaluated for California, using geothermal or waste heat. These use either amine-functionalized sorbent beds or ceramic monoliths for the contactors, which represent between 81–89% of the total capital cost. Small variations in configurations result in incremental costs for the addition of heat-pump equipment for the upgrading of low-temperature geothermal fluids, and a small decrease in cost for the heat exchanger used in the waste heat scenario due to the higher temperature of fluids employed.

Inspection of the operating costs shows that the power required for fan and vacuum pumping, as well as the maintenance and labor charge is relatively constant amongst the three scenarios. However, large discrepancies exist outside of the common components, most notably the additional power required of the heat pump to deliver geothermal fluid and operating temperature (ca. $38 per ton of CO_2 assuming $0.06 per kilowatt hour) and the cost incurred by use of plant waste heat (ca. $32 per ton of CO_2 assuming compensation for displaced electricity production, at a market value of $0.06 per kilowatt hour). An alternative configuration of the waste heat scenario involves the

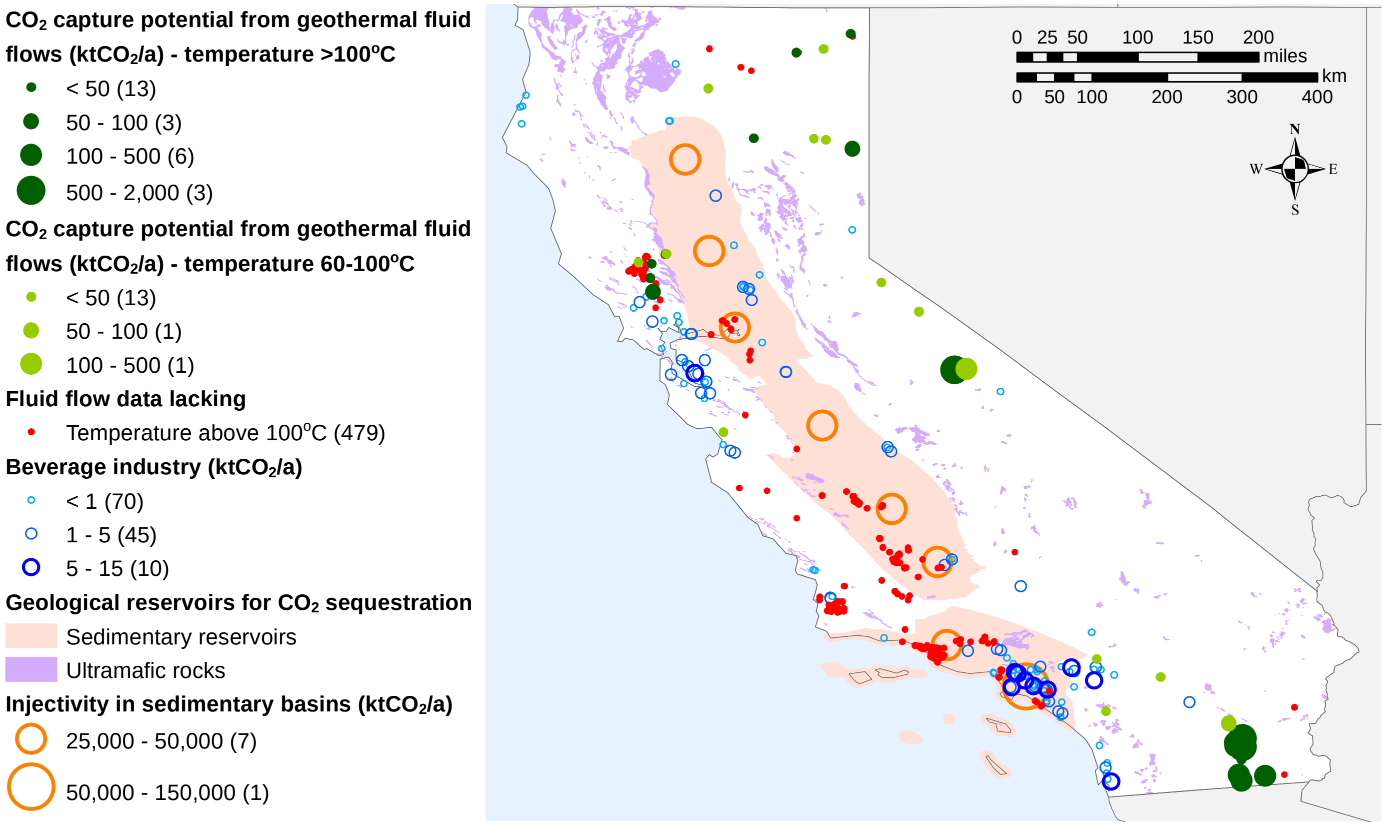


Figure 40. *Potential of direct air capture paired with existing geothermal and CO_2 sequestration in California.*

Table 28. *Details of the emissions, available waste heat, and the subsequent size of the direct air capture plant and CO_2 net removed per industrial sector.*

Industry	Number of facilities	Total emissions [ktCO_2-eq]	Emissions from SC [ktCO_2-eq]	Total thermal energy [MW]	Available waste heat [MW]	Size of the DAC plant [ktCO_2]	Net CO_2 removed [ktCO_2]
Refining	18	31,308	17,709	4,600	571	2,925	1,857
Minerals	19	5,825	650	169	134	685	435
Metals	2	220	220	57	17	89	56
Total	39	37,353	18,580	4,826	722	3,699	2,349

ktCO_2/yr = kilotons of CO_2 per year

inclusion of equipment for the direct use of waste heat to produce electricity to satisfy the direct air capture electrical power requirement (20% of total energy or ca. 1.5 gigajoules per ton of CO_2). This system had a slightly higher capital expense total (compare at \$146 per ton of CO_2) and a slightly lower operating expense total (compare at \$56 per ton of CO_2). However, because of the waste heat diverted for electricity production, this configuration results in a direct air capture capacity that is 1.75x lower than that of the configuration where all waste heat is assigned to the thermal processing. **The lowest-cost new build geothermal option yields annualized costs of \$191+\$75 = \$266 per year per ton.**

It is of interest to consider the total embodied emissions associated with direct air capture schemes. Given this basis for CO_2 separation from air, full supply chain costs to storage opportunities can be calculated through the addition of compression, transport, and injection costs. Since the removal of CO_2 from the atmosphere requires significant contactor surface area and subsequent materials, embodied emissions were also included in the estimate; however, it was found that the embodied emissions represented less than 1% of the total cost of the net removed CO_2. The CO_2 emissions associated with trucking were also included in this estimate.

Direct air capture with geologic storage appears to be technically feasible in California. The current technical approaches suggest that the land used will be a primary consideration, particularly for the energy source (180 to 310 megawatts continuous power per million tons of capacity per year). Powering these facilities with either geothermal power, or natural gas with greater than 90% capture of the fossil carbon, provides systems that are relatively compact and still achieve their goal of reducing total CO_2 in the atmosphere. The existing and potential geothermal energy in California could power as much as 16 million tons of sorbent-based direct air capture per year. Capture by solvent-based systems powered by natural gas is essentially unlimited, provided that the fugitive emissions from natural gas transmission are accounted for, and hopefully eliminated. We recommend using local natural gas sources to simplify this issue and permit emission-free natural gas to be ensured.

Costs of Direct Air Capture from Geothermal and Waste Heat

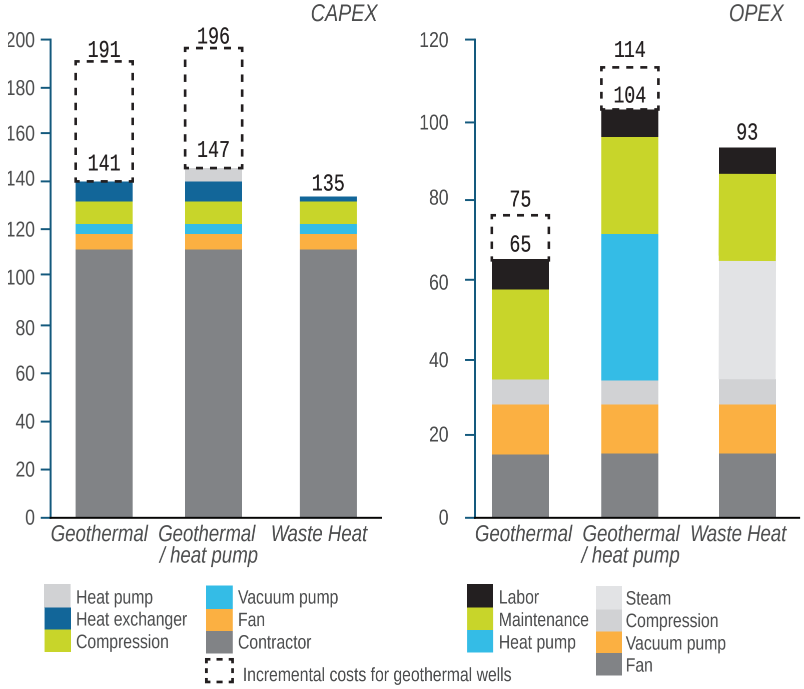


Figure 41. *Capital (left) and operating (right) expense breakdown for three direct air capture configurations: using geothermal fluid at sufficient operating temperature (100°), upgrading of geothermal fluid to sufficient operating temperature, and direct use of waste heat from industrial plants. Costs are based on a hypothetical plant capturing 100,000 tons of CO_2 per year. Total of \$206 per ton for geothermal using existing resources*

CHAPTER 6

Permanent Sinks

SUMMARY

Most of the CO_2 (about 100 million tons per year) isolated by two pillars of our negative emissions approach, biomass conversion and direct air capture, will require *long-term geologic storage*.

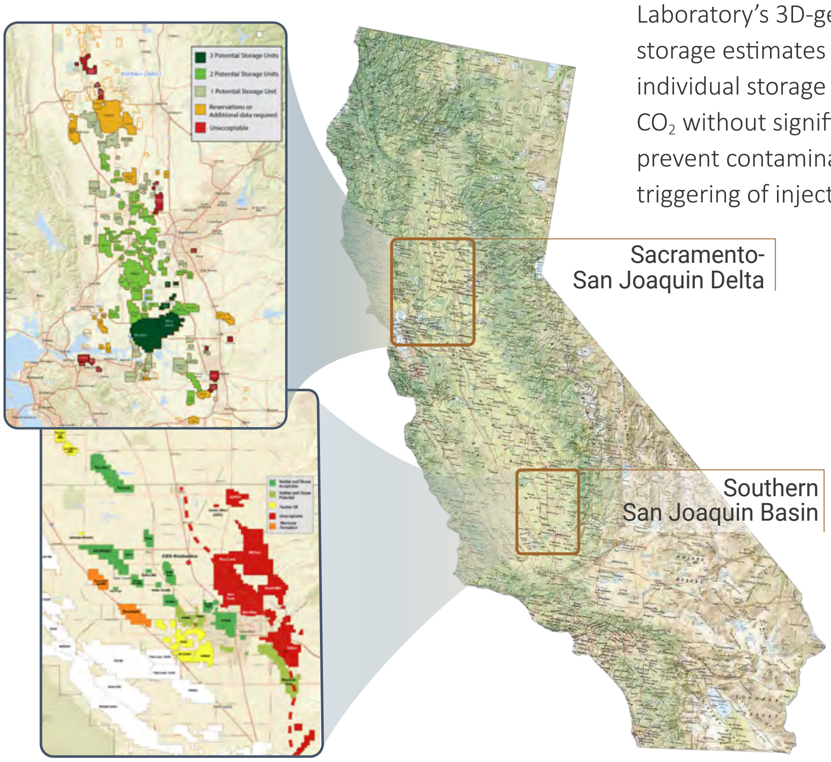
The feasibility of long-term geologic storage of CO_2 has been demonstrated through research programs in the United States and around the world that now store about 35 million tons per year, and through the similar process of enhanced oil recovery using CO_2 injection, which currently puts about 60 million tons per year underground in the United States. In California the CO_2 would be stored in the same rocks that have held oil for millions of years.

In this chapter, we assess the geologic integrity, location, and cumulative storage capacity of California's potential storage locations, focusing on potential saline storage locations. Previous estimates of storage capacity within California were performed at basin scale. In this chapter we assess California's reservoir storage potential at the intermediate resolution needed for a more accurate regional model of reservoir characteristics, storage capacity, and location for inclusion in transportation analyses. We provide two of these intermediate-resolution analyses (Figure CS-6 below) within the Sacramento Basin and along the eastern flank of the Southern San Joaquin Basin, the latter based on Lawrence Livermore National Laboratory's 3D-geologic model of the region. High-resolution storage estimates that more critically assess the integrity of individual storage complexes in terms of their ability to sequester CO_2 without significant leakage over decadal or longer timeframes, prevent contamination of groundwater resources, and avoid triggering of injection-induced seismicity will eventually be required.

Scope of Chapter

Regional models of reservoir characteristics for CO_2 storage including storage capacity, geologic integrity, and location. Sites assessed in detail:

- Sacramento Basin, divided into 3 primary formations: the Mokelumne River, Starkey, and Winters
- Formations in the eastern flank of the Southern San Joaquin Basin: Etchegoin, Santa Margarita, Olcese, and Vedder



Key Findings

Previously estimated storage capacity of onshore saline formations in California's ten largest basins (which include active and depleted oil fields and saline formations) range from 75 to 300 billion tons of CO_2. For the two locales we examined in the Central Valley alone, our most conservative intermediate-resolution estimate yields capacities of ~17 billion tons, more than enough to meet the negative emission needs of California.

Introduction

Many of the carbon capture processes discussed above require long-term geologic storage of CO_2 to achieve negative carbon emissions. Biochar in soils or CO_2 mineralization in cement can provide some long-term storage, but the bulk of long-term CO_2 isolation will require geologic storage. Achieving negative emissions in California will likely require injection of 50–125 million tons of CO_2 per year, which is well beyond that realized in current geologic storage operations and will likely necessitate the development of multiple storage complexes with associated transport networks. Here, as a basis for techno-economic analysis of an envisioned capture-transport-storage network, we assess the geologic integrity, location, and cumulative storage capacity of potential storage complexes. As in previous analyses, estimates are impacted by imprecise knowledge of the variations in geologic characteristics for the potential storage complexes, including injection efficiency, compartmentalization, stratigraphic and diagenetic complexity, and others. As such, we adopt a conservative approach to storage capacity estimation. Here we focus on potential saline storage locations. We did not attempt to differentiate saline storage capacity from storage in depleted oil and gas fields or potential storage associated with enhanced oil recovery.

The feasibility of long-term geologic storage of CO_2 is manifest in numerous natural accumulations, many of which are "mined" for industrial applications, including secondary/tertiary oil recovery. The primary use of CO_2 from natural accumulations is enhanced oil recovery in the Permian Basin, which amounts to greater than 60 million tons per year [213] and demonstrates the feasibility of transport and injection at the scale required to achieve negative CO_2 emissions in California. The preliminary estimated storage capacity of onshore saline formations in California's ten largest basins (which include active and depleted oil fields and saline formations) is encouraging, ranging from 75 to 300 billion tons of CO_2 [214]. Storage estimates for the Central Valley alone vary between 50–200 billion tons, equivalent to greater than 400 years of storage for injection rates of 125 million tons per year. These are low-resolution estimates, however, and may define the ultimate resource, but not necessarily that which can be practically or economically utilized. In addition, some of the potential storage complexes lie within densely populated urban areas and are not envisioned as viable candidates for early adoption.

High-resolution storage estimates that more critically assess the integrity of individual storage complexes in terms of their ability to sequester CO_2 without significant leakage over decadal or longer timeframes, prevent contamination of groundwater resources, and avoid triggering of injection-induced seismicity will eventually be required. Existing oil production and fluid injection data can be utilized to inform those high-resolution estimates, if publicly accessible.

Fully site-specific assessment of storage capacity, injectivity, and plume migration will require more detailed stratigraphic evaluation, on-site injection tests, transport simulations, etc., that are beyond the scope of this assessment. Such analysis would better prioritize site selection necessary for the optimal geographic distribution of injection sites and the design of transport networks required to aggregate CO_2 from various sources and distribute it among the various injection sites. Our goal is to assess California reservoir storage potential at an intermediate resolution needed for a more accurate regional model of reservoir characteristics, storage capacity, and location for inclusion in life-cycle analysis.

Based on criteria such as the presence of significant porous and permeable strata, thick and pervasive seals, and sufficient sediment thickness to provide supercritical-state pressures for CO_2 injection (>800 meters, or >2,625 feet), [214]. Downey and Clinkenbeard screened the onshore sedimentary basins within California to determine preliminary suitability for potential CO_2 storage. The most promising are the larger Cenozoic marine basins, including the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda marine basins (Figure 42). Utilizing maps of areal extent and storage formation thickness (isopach maps) the gross volume of the aggregated storage formations can be constrained. The authors estimated static CO_2 storage capacities by combining estimates of porosity and production data for depleted gas fields and potential utilization of CO_2 in enhanced oil recovery applications (Figure 43). These estimates include an uncertainty factor of 4 associated with pore volume utilization, essentially the percentage of available porosity that can be accessed during CO_2 injection, which varies from 1–4% and cannot be more precisely assessed without characterization of individual sites. They estimated the storage capacity of saline formations in California's ten largest basins ranges to be from 75 to 300 billion tons of CO_2. Potential CO_2 enhanced oil recovery storage was estimated at 3.4 billion tons. Cumulative production from gas reservoirs suggests a CO_2 storage capacity of 1.7 billion tons.

Figure 42. *Sedimentary basins with CO_2 storage potential within California*

Of the ten suitable onshore basins, the Los Angeles, Ventura, Salinas, Eel River, La Honda, Cuyama, Livermore, and Orinda either lie within densely populated regions, or are too small to include in a first-generation source-sink network analysis. The Salton Trough has the second largest potential storage capacity but is a terrestrial, as opposed to marine, basin. While it does have sandstone units and lacustrine shales, these terrestrial deposits lack the lateral continuity found in marine basins and may not have sufficient caprock seals. While many of these basins may ultimately contribute to California's aggregate storage capacity, we restrict our analysis to the largest basin, the Sacramento–San Joaquin basin which constitutes the Great Valley geologic province or Central Valley.

Intermediate Resolution Evaluation of California Storage Capacity

The low-resolution storage capacity estimates of 51–205 billion tons of CO_2 for the Central Valley are based on estimates that aggregate the volumes of various formations. A more accurate estimate can be obtained by assessing the storage volume for individual target formations. Such estimates are still prone to uncertainties associated with porosity utilization but provide higher resolution estimates of formation volumes and potential constraints such as caprock thickness, depth, and conflicts with underground sources of drinking water (USDW). Below we review a formation-based assessment of storage capacity for three formations in the Sacramento Basin [215] and provide a new formation-based assessment of storage along the eastern flank of the Southern San Joaquin Basin based on a 3D-geologic model constructed by Wagoner [216]. Both models utilize stratigraphic data largely based on formation top depths "picked" from well logs and available seismic data to construct maps of storage formation depth, storage formation thickness, and caprock formation thickness. Spontaneous potential well logs, aka "SP logs", can be used to assess the volume of sandstone within each formation which, coupled with estimates of sandstone porosity, can be used to generate porosity volumes.

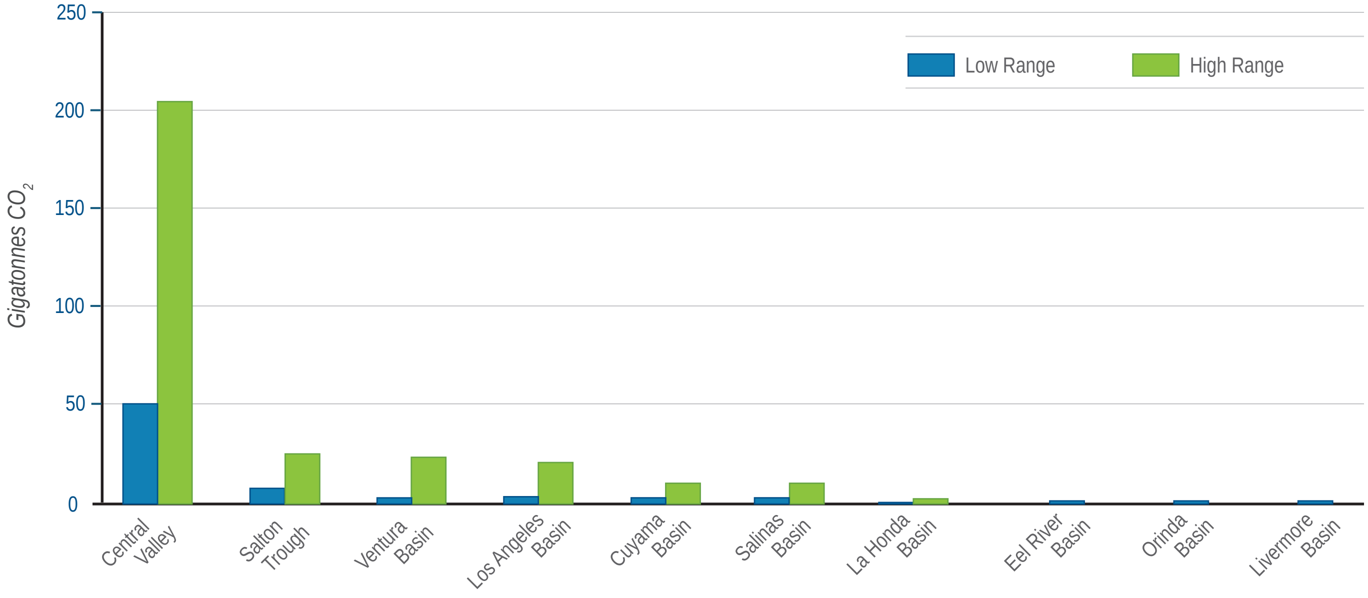


Figure 43. *Storage capacity estimates for 10 California sedimentary basins (after Downey et al., 2006)*

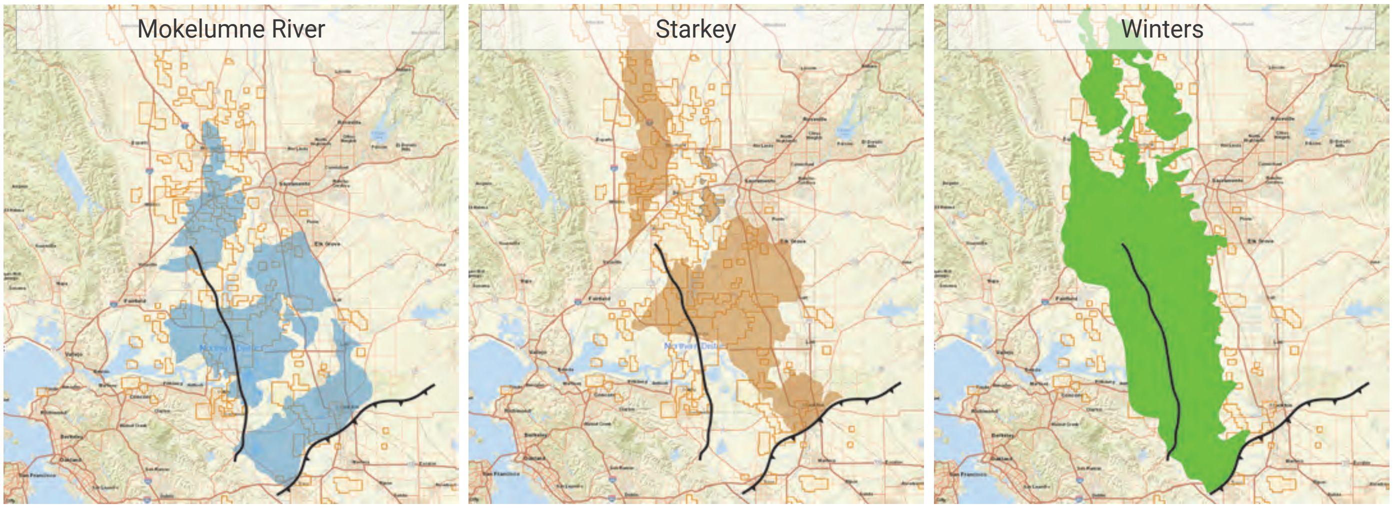


Figure 44. *Acceptance polygons for the Mokelumne River, Starkey, and Winters Formations. Acceptance is based on formation top depth greater than 1,000 meters, at least 100 feet of caprock thickness above the storage unit, and formation water salinity greater than 10,000 parts per million total dissolved solids.*

Storage Capacity of the Sacramento Basin

The Sacramento Basin is a large synclinorium extending from the Sierra Nevada in the east to the Coast Range in the west (Figure 42) [217]. Sedimentary strata on the eastside of the basin dip to the west (Figure 45) and are cut by the Midland Fault, which trends northwest–southeast through the center of the basin (Figure 44). Some sedimentary units can be found on both sides of the fault but are at greater depth on the west side (offsets become greater with formation age).

Downey and Clinkenbeard [215] assessed the storage capacity of the three major sandstone units in the Sacramento Basin: the Mokelumne River, Starkey, and Winters formations. The acceptance criteria were formation top depth greater than 1,000 meters, to ensure injection of supercritical CO_2, and an overlying caprock unit at least 100 feet thick (Figure 44). The authors also eliminated regions where submarine canyons incised one of the units. We note that the target storage formations may still be present in these regions incised by submarine canyons but are obviously thinner than the regions outside the canyons. As such, eliminating regions incised by submarine canyons may be overly conservative, as substantial undisturbed formation volume remains. Nevertheless, we follow the authors' approach here. We also note that the Domengine formation, capped by the Nortonville shale, could represent additional storage capacity but, given its regional continuity and that it is the shallowest potential storage formation, it constitutes a favorable buffer zone to ameliorate any leakage from the potential primary storage complexes below. As such, its exclusion here represents another conservative assumption.

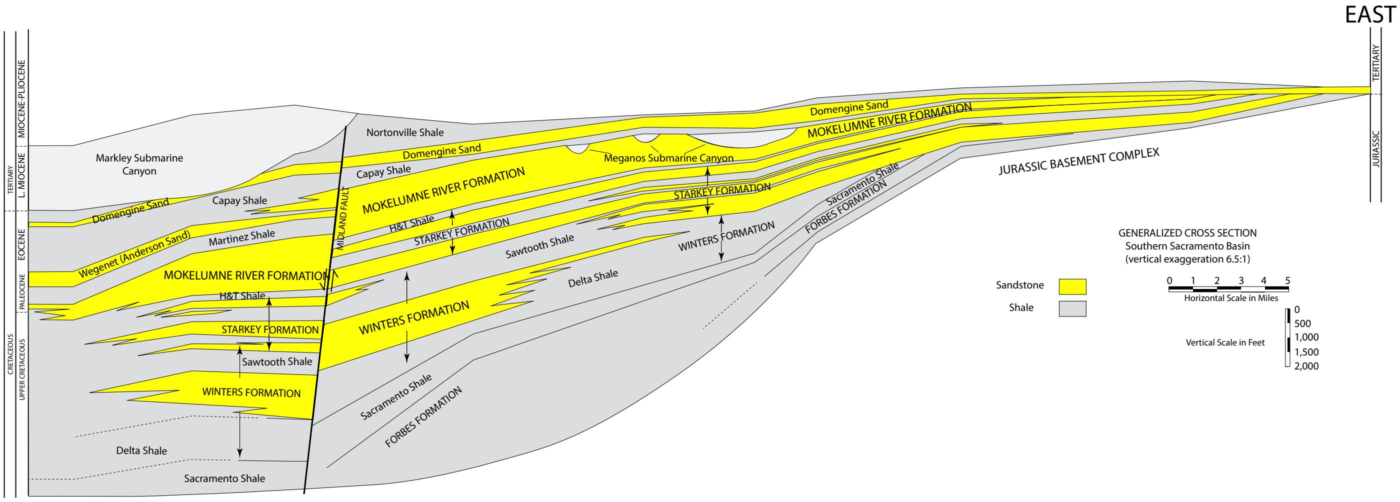


Figure 45. *Geologic cross-section of the Sacramento Valley [modifiied after Downey and Clinkenbeard 2010].*

Table 29. *Sacramento Basin estimated CO_2 storage capacity.**

Storage Formation	Billion tons CO2 (E=0.01)	Billion tons CO2 (E=0.04)
Mokelumne River	1.0	4.0
Starkey	1.0	4.1
Winters	1.2	4.9
Total	**3.2**	**13.0**
Sacramento Basin West-CARB Phase I	11.4	45.9
Capacity reduction using high resolution assessment relative to WestCARB Phase I	~72%	

* Capacity estimated using bounding value injection efficiencies, "E", the fraction of porosity accessed by CO_2

It is instructive to note the reduction in gross formation volume that is achieved in these more highly constrained, formation-based assessments. For instance, the areal extent of gross sandstone for the Mokelumne River formation is 1,908 square miles. Subtracting the area occupied by submarine canyon reduces that area by 20% (1,528 square miles). Eliminating regions with formation top depth less than 1,000 meters reduces the area by another 24% (1,075 square miles), and finally, eliminating regions with less than 100 feet of caprock seal reduces the area another 1%. The area is reduced by an additional 6% by eliminating regions where the salinity of the formation water is less than 10,000 parts per million total dissolved solids. In all, imposition of these higher resolution constraints reduces the areal extent of the storage formation to 49% of the gross sandstone area. Similar analysis of the Starkey and Winters formations, which are not influenced by salinity constraints, result in reductions to 40% and 86% of the original gross sandstone areas, respectively.

The southern Sacramento Basin constitutes approximately 22.4% of the Central Valley area assessed in the Phase I WestCARB assessment, yielding an estimated storage capacity of 11.4–45.9 billion tons. The storage capacity estimate obtained from this higher resolution assessment range between 3.2 and 13.0 billion tons (Table 29), approximately a 72% reduction relative to the low-resolution estimate. A similar reduction, applied to the Central Valley as a whole, yields a storage capacity of 14–146 billion tons, which at 100 million tons per year (0.1 billion tons per year) can accommodate between 142 and 1,470 years of CO_2 storage.

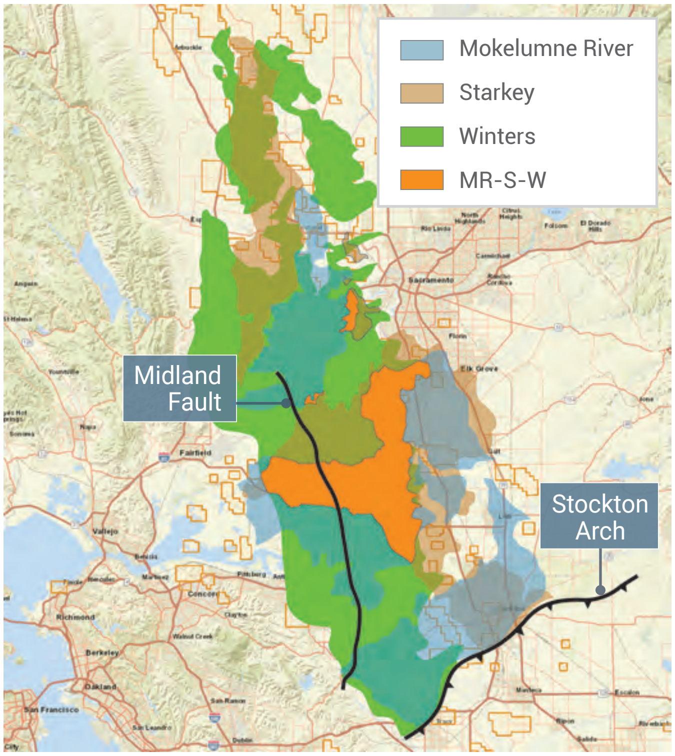


Figure 46. *Stacked acceptance polygons for Mokelumne River, Starkey and Winters Formations. The individual formations are shown in the legend. "Mixed" colors are indicative of stacked storage opportunities in more than one unit. The orange region, labeled MR-S-W denotes the area where stacked in the Mokelumne River, Starkey and Winter Formations is possible.*

Carbon storage within multiple, vertically stacked formations, aka "stacked storage" at a single site may ameliorate some of the risks associated with potential loss of injectivity, etc. encountered during injection. The distribution of acceptable for the three storage formations in the Sacramento Valley do offer the potential for stacked storage in 2 or 3 of the target formations with stacked storage in formations occurring within the central portion of the Sacramento Delta. (Figure 46).

Storage Capacity of the Southern San Joaquin Basin

Unlike the Sacramento Basin, where the storage potential is largely confined to three formations, the Southern San Joaquin Basin, roughly three times as large as the Sacramento Basin, is more stratigraphically diverse with numerous active oil fields [218], [217]. Structurally, the San Joaquin Basin is similar to the Sacramento Basin—a broad, asymmetric synclinorium roughly confined by the Sierra Nevada on the east and the San Andreas Fault on the west (Figure 47 and 48). The area of the San Joaquin Basin represents roughly 77.6% of the total Central Valley. Combined with total storage capacity estimated by WestCARB, this yields a low-resolution storage capacity of 39.6-159 billion tons for the San Joaquin Basin.

There is currently no publicly accessible, quantitative formation-specific geologic model that covers the entire Southern San Joaquin Basin region. The best available 3D geologic model was assembled by Lawrence Livermore National Laboratory over the past two decades [216]. The Lawrence Livermore National Laboratory model incorporates stratigraphic data obtained from well logs and seismic data and is best constrained in the region immediately west–northwest of Bakersfield where the data density is highest.

Figure 47. *Map of Southern San Joaquin Basin showing the location of Lawrence Livermore National Laboratory (LLNL) 3D geologic model (Wagoner, 2009) and the United States Geological Survey Petroleum Assessment Model (Scheirer and Magoon, 2007). The dashed lines show the approximate location of the cross-section in Figure 48.*

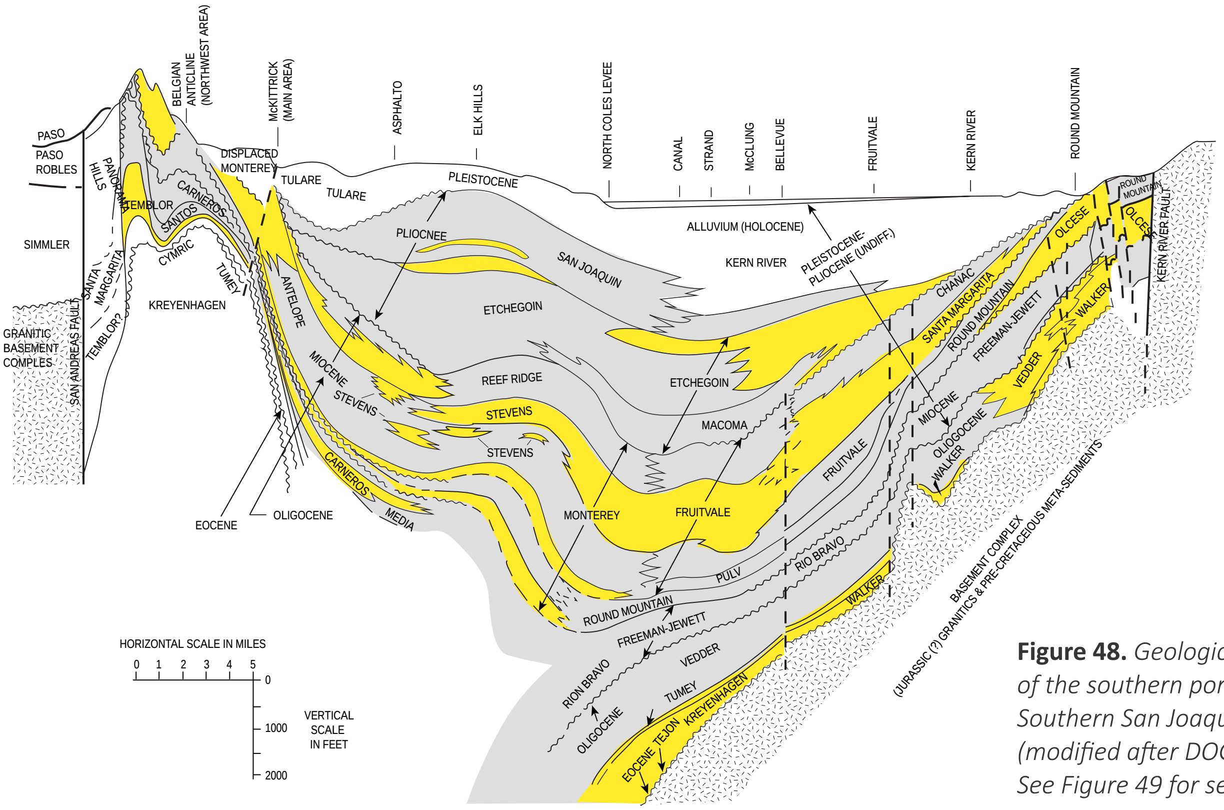


Figure 48. *Geologic cross-section of the southern portion of the Southern San Joaquin Basin (modified after DOGGR [218]). See Figure 49 for section location.*

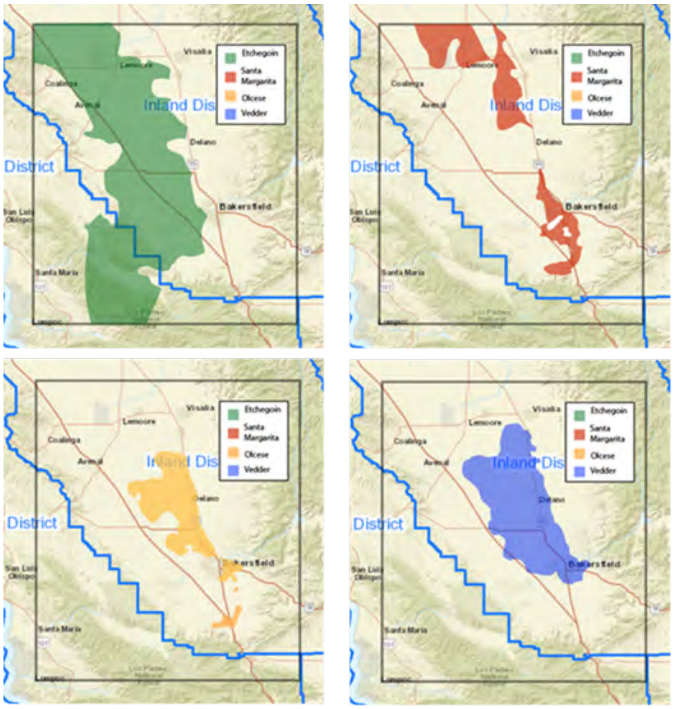


Figure 49. *Acceptance polygons for the Vedder, Olcese, Santa Margarita, and Etchegoin formations in the Southern San Joaquin Basin. Acceptance is based on formation top depth greater than 1,000 meters to at least 100 feet of caprock thickness above the storage unit and formation water salinity greater than 10,000 parts per million total dissolved solids.*

It does not capture intra-formational spatial variations in the sand/shale ratio and porosity, requiring individual formations to be treated as essentially homogeneous units with estimated porosity (Table 30).

We note that the Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California performed by United States Geologic Survey [219] covers a larger region of the southern portion of the Central Valley relative to the LLNL model (Figure 47). Rather than utilizing individual formations, the United States Geological Survey model combines multiple formations of the same depositional age into composite chrono-stratigraphic units that can be correlated over large regions of the basin. The United States Geological Survey model was assembled for hydrocarbon resource assessment and though related to CO_2 storage capacity is not directly applicable. Utilization of the model to obtain storage capacity estimates would require not only estimation of intra-formational spatial variations in the sand/shale ratio and porosity but also estimation of the volume of each formation within each chrono-stratigraphic unit. The model also extends into regions of active hydrocarbon production. As such, we restrict our assessment to areas covered by the Lawrence Livermore National Laboratory model.

The potential storage formations in the eastern portion of the Southern San Joaquin Basin are the Etchegoin, Santa Margarita, Olcese, and Vedder formations. Selection criteria similar to those used in the Sacramento Basin, deeper than 1,000 meters with 100 feet of overlying caprock, have been used to define acceptance polygons for each formation (Figure 49). The potential for stacked storage exists throughout the regions (Figure 50). An isopach map of formation thickness for each of the storage formations within the acceptance polygons has been constructed (e.g., Figure 51) and combined with estimates of sand fraction and porosity to obtain the pore volume (Table 30). The total estimated cumulative storage capacity for the Etchegoin, Santa Margarita, Olcese, and Vedder formations is between 14.1 and 56.4 billion tons, respectively, for injection

Table 30. *Southern San Joaquin Basin Storage Capacities.*

					Storage Capacity (Gt)	
Formation	Gross volume -1,000 m³	Estimated Fraction Sand	Estimated Porosity	Gross Pore volume (m³)	Injection Efficiency E=0.01	Injection Efficiency E=0.04
Etchegoin	8.33E+12	0.8	0.25	1.67E+12	11.7	46.7
Santa Margarita	1.38E+12	0.5	0.25	1.73E+11	1.2	4.8
Olcese	2.76E+11	0.7	0.25	4.83E+10	0.3	1.4
Vedder	7.33E+11	0.7	0.25	1.28E+11	0.9	3.6
Total					14.1	56.4

700 kg per cubic meter is used for the density of supercritical CO_2

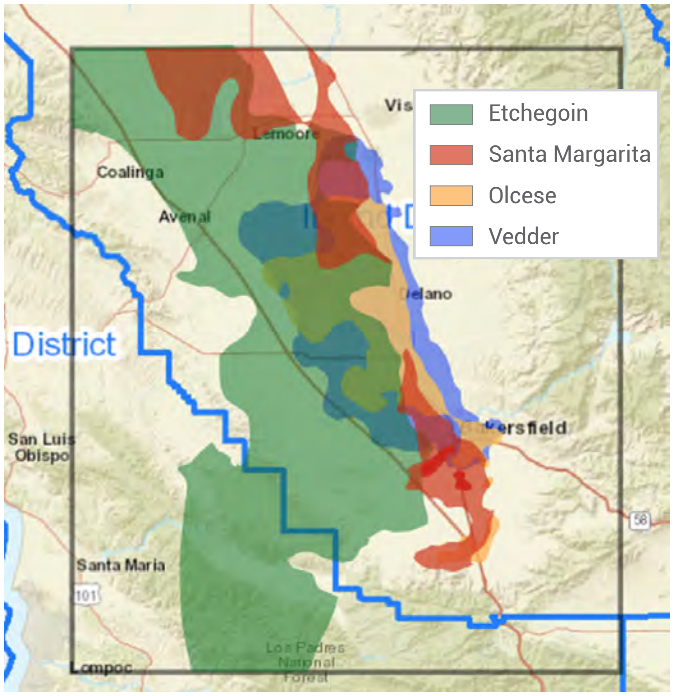


Figure 50. *Stacked acceptance polygons for the Vedder, Olcese, Santa Margarita and Etchegoin formations. The individual formations are shown in the legend. "Mixed" colors are indicative of stacked storage opportunities in more than one unit.*

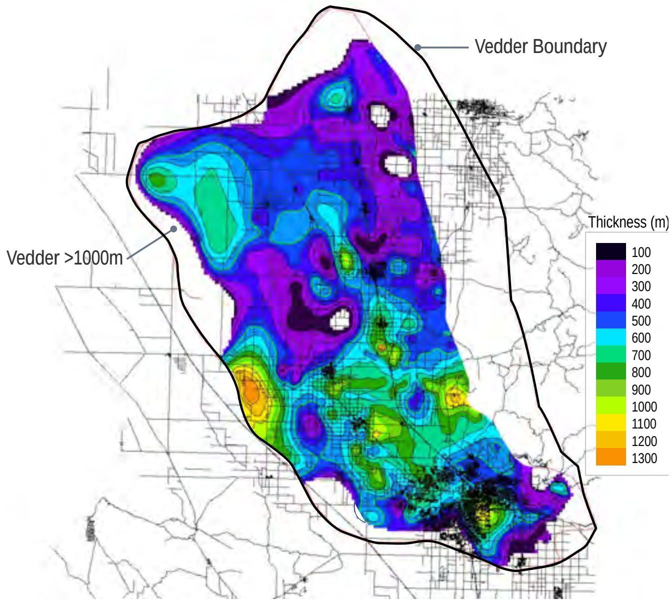


Figure 51. *Isopach map for the Vedder formation. Contours display variations in formation thickness for the 1,000 meters acceptance polygon (See Figure 38). The black outline marks the location of the Vedder formation boundary. The region between the formation boundary and the isopach boundary is that eliminated by the acceptance criteria.*

efficiencies of 1% and 4%, equivalent to 141 year and 564 year of storage at 100 million tons per year. These should be taken as lower limits as we have not estimated the storage capacities in sand-rich formation to the west, such as the Stevens, Temblor, Carneros, and McDonald sands.

Saline Storage Capacity: Summary of the Southern San Joaquin Basin

In summary, the estimates of storage capacity in the Central Valley are imprecise owing to incomplete subsurface data and the factor of 4 uncertainty attributed to injection efficiency. Nonetheless, even the most conservative estimates yield capacities of ~3 billion tons and ~14 billion tons for the Sacramento Basin and Southern San Joaquin Basin, respectively. Hence, a conservative estimate of the storage capacity for the entire Central Valley is ~17 billion tons, equivalent to 170 years of storage at 100 million tons per year. Equivalently detailed evaluations of the parts of the Central Valley not covered by our current models, such as the region between the Southern San Joaquin Basin region and the Stockton Arch and the region west of the Midland Fault in the Sacramento Basin, are likely to significantly increase this estimate of storage capacity.

Conclusion

Until now, the locations and storage capacities of suitable, permanent storage sites within the State have been based on high-level, basin-scale assessments. We advanced this understanding to location-specific knowledge by assessing the storage capacity associated with California's oil and gas fields, as well as deep saline aquifers that share the same geology, for two extremely well studied areas with ample, publicly available data: the Sacramento Basin and Southern San Joaquin Basin. Both these regions have been sites of extensive oil and/or gas production, which results in the availability of geologic data. We used this data to evaluate CO_2 storage capacity, storage security, and the ability to comply with the strict regulations and standards that govern current underground CO_2 storage.

We conclude that these areas will be safe and effective storage sites. At depths below 3,000 feet, CO_2 converts to a liquid-like form that has about the same density and viscosity as oil. The fact that the geologic barriers in these regions have held oil and gas underground for millions of years means that they are well-suited to secure storage of CO_2. Site-specific factors such as faulting and man-made penetrations will need to be evaluated carefully for each site storage operation, but our review of about 50% of the likely good storage zones in the Central Valley indicates that at least 17 billion tons can be stored there, with the upper limit being 200 billion tons. Seventeen billion tons would provide more than 100 years of capacity at the rate that we anticipate California will require negative emissions.

Figure 52 focuses on the two regions we have evaluated, the Sacramento River Delta and the Southern San Joaquin Valley, showing the administrative boundaries for the oil and gas fields in those regions (which are the source of most of the high-quality data available to us). Storage areas that appear to meet the Federal (EPA Class 6) and State (CCS LCFS Protocol) requirements are shown in greens and yellows, while administrative areas that fail one or more criteria as described above are shown in orange and red. We consider areas with more than one storage unit available (so called stacked storage) to offer more storage options and be more likely to efficiently use infrastructure like pipelines and monitoring systems. We expect that geologic storage of CO_2 can also be conducted outside these administrative, but that characterizing specific storage sites still requires careful evaluation based on more localized information than we have used in this intermediate scale evaluation, including characterization well(s) to confirm the storage units and cap rocks.

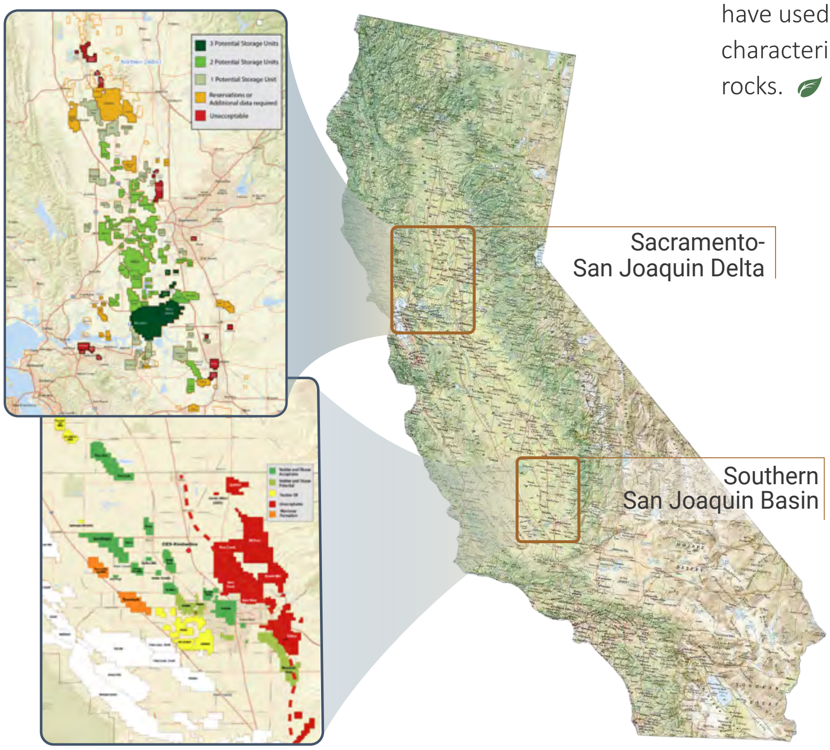


Figure 52. *Two prospective areas for underground geologic storage. Oil and gas fields are highlighted. Color indicates the degree of conformance with existing State and Federal standards for geologic CO2 storage, as well as additional safety constraints. White fields have not been evaluated.*

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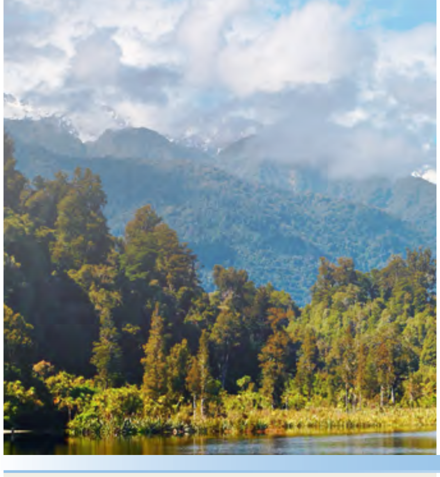
CHAPTER 7

Transportation and System Integration



SUMMARY

The majority of negative emissions pathways described in this report require transport of biomass or CO_2 throughout the State. In Chapter 3 we found that forest biomass resources are concentrated in the northwest, agricultural residues in the Central Valley, and municipal solid waste in the populated south, while in Chapter 6 we identified promising geologic storage sites at the northern and southern ends of the Central valley. The problem of transport is how to move carbon from the source regions to the storage sites, allowing for placement of the biomass conversion facilities.

We built a county-level model that aggregates biomass feedstocks, transports it to conversion facilities, and moves the resulting CO_2, along with CO_2 from direct air capture and existing biogas facilities, to geologic storage hubs near Bakersfield and in the Sacramento River Delta region. The costs of transport for a given pathway depends on the distances, size of the conversion facility (flow rate of carbon), and availability of rail or pipelines. In our system-level scenarios, we assume a CO_2 trunk pipeline can be constructed along existing natural gas pipelines in the Central Valley, but not elsewhere in the state. We also make use of currently active rail lines, which serve 36 out of 58 counties.

Key Findings

We find that rail is generally the most economical option for transporting biomass. CO_2 transport costs are dependent on flow rate, where pipeline is most economical above about 2,000 tons of CO_2 per day, and rail more economical for production levels below that over typical distances. Gasification and combustion plants are best sited near CO_2 storage facilities or major pipelines, with the biomass transported by rail. Pyrolysis plants are generally best sited near the biomass supplies, with the best mode of transporting the CO_2 depending on location. Transport costs are overall higher for pyrolysis per ton of CO_2 removed because of the smaller plant sizes and the lower yield of negative emissions per unit of biomass.

Overall, we find that transportation is a relatively small portion of the system cost. The system-wide average transport costs ranged from \$10 per ton of CO_2 removed for the Gasification Priority Scenario to \$18 per ton for the Pyrolysis Priority Scenario.

Scope of Chapter

Cost and logistics of transporting biomass and CO_2 for the negative emissions system. We compare the costs of moving carbon by different modes (truck, rail, pipeline), considering factors such as:

- Conversion technology (gasification, pyrolysis, combustion)
- Facility placement
- Pipeline access
- Rail access

We then calculate the lowest-cost mode for each biomass type and each county in the State. We estimate the system wide transport costs for the three technology scenarios to be assembled in Chapter 9. We also calculate the overall freight demand and emissions from transport for the negative emissions system.

Introduction

This chapter assesses the transport of materials necessary to integrate the carbon collection, carbon conversion, and carbon storage methods discussed elsewhere in the report. In Chapters 3 and 4, we found that a large fraction of negative emissions targets can be met by collecting and converting biomass available in the state. This is a significant transportation challenge not faced by natural solutions. Direct air capture transportation issues can mostly be solved by locating the facilities at the storage sites, although use of geothermal energy will require CO_2 transportation.

Our analysis shows that forest biomass resources are concentrated in the northwest of the state, agricultural residues in the Central Valley, and municipal solid waste and gaseous wastes in the populated areas of south. As we found earlier, the vast majority of CO_2 to be removed from the atmosphere will have to be stored geologically to achieve the negative emissions goals set out in Chapter 1. There are various options for geologic storage sites in the state, but we have identified the most promising first candidates in San Joaquin County and in Kern County, located at the northern and southern ends of the Central Valley.

The transport problem is a question of how to move carbon from the biomass source regions to the storage sites in the Central Valley: forest biomass or its products from the northwest, agricultural residues from elsewhere in the Central Valley, and biogas and municipal waste or its products from the populated south.

There are multiple options for the mode of transport (truck, rail, pipeline) and the form of carbon to be transported. All the carbon materials can be transported by truck or rail, while the gases—CO_2, renewable natural gas, biomethane, and hydrogen—can also be transported by pipeline. Transport of any of the materials by ship is also possible and might be worth investigating for the movement of forest biomass from the north coast to the central valley via, for example, the Port of Stockton. However, waterborne transport within California overall is limited and we do not consider it in this report.

As an example, biomass can be converted to hydrogen near the source, leaving CO_2 to be transported to the storage site in gaseous form. Alternately, the biomass can be transported to the storage site and converted to fuel nearby. The question of where to site carbon conversion facilities is especially important for forest biomass and agricultural residues.

Finding an optimal design for the carbon logistics network is not appropriate at this time because of the uncertainties about future parameters and practical limitations of infrastructure construction. Instead, we examined several reasonable scenarios and estimated the total transport costs for each. For simplicity, we don't consider the transport of fuels sold to market. Liquid fuels and hydrogen produced from biomass will require transport to end users, but we assume that this cost is accounted for in the wholesale gate prices that we use when calculating the technology costs in Chapter 4. The hydrogen sale price of $2.90 per kg, for example, is much lower than the retail fuel price at the pump, and partly this is to account for hydrogen transport. We assume that electricity and biomethane move by the existing grids without significant need to build new capacity. The selected biogas utilization scenario (4b) produces 1.1 GW of electricity – about 4% of California's consumption in 2018. The quantity of biomethane injected into the natural gas network in this scenario is likewise about 4% of 2018 consumption.

The major focus of this chapter is on transport of CO_2 and solid biomass. Although there are many examples globally and within California of biomass transported for energy, bioenergy deployment is currently limited in large part by the high cost of biomass collection and transport compared to fossil fuels [220]. The present analysis departs from previous work on biomass transport for energy in two important ways. First, we have found the value of biomass as a medium to capture CO_2 is much higher than its value as an energy source. Second, while biomass is less energy dense than competing fossil fuels, it is fairly carbon-dense compared to alternatives, with about 50% carbon by dry weight.

In this chapter, we first describe the modes of transport and lay out our associated assumptions for the cost of transport by truck, rail, and pipeline. We then present a general analysis about the best choice of mode when multiple options are available. Finally, we estimate the transport costs for the recommended negative emissions pathways to appear in the supply curves in the next chapter.

The facilities that produce biogas: wastewater treatment plants, landfills, and manure facilities, are already in fixed locations. We considered options for transport and central treatment of raw biogas (combined CO_2 and methane) and found this is impractical over inter-county distances. However, low pressure, fiberglass pipeline networks have been built for aggregating raw biogas from closely grouped agricultural sources. This type of scheme was assumed for manure sources in Chapter 4.

CO_2: Refrigerated or Compressed?

In general, CO_2 is best stored and transported as a liquid, and there is a choice between refrigerating to lower temperatures and lower pressures or storing at ambient temperature and higher pressure. In current practice, CO_2 is moved in pipelines at ambient temperature and 80–140 bar and in trucks at about -40°C and 20 bar pressure. Short term, onsite CO_2 storage tanks also tend to be refrigerated. The reason for this is that lower-pressure storage is more economical when heat absorption can be controlled. In a pipeline, insulation is less practical because of the large surface area, but in storage or transport tanks, a vacuum insulation layer can keep refrigerated CO_2 sufficiently cold for several days (manufacturers typically specify leak-off rates less than 0.1% per day [221] .

To illustrate the trade-off, Figure 53 shows the estimated installed cost of a CO_2 storage tank with a 28 ton capacity. The overall dimensions are adapted from the Linde size 300 cryogenic storage tank [221]. The wall thicknesses, fabrication cost, and installation factor are calculated by standard engineering methods following Towler and Sinnot [96].

As reflected in the cost estimate, pressure vessels rated for 100 bar (compressed CO_2 at ambient temperature) are much more expensive than those rated for 20 bar (refrigerated CO_2 at 40°C), even accounting for the extra vessel wall supporting a vacuum insulating layer. The thicker walls in the 100-bar vessel simply require much more stainless steel. The advantage of refrigeration is even more pronounced for truck transport, both because the containers need to be more robust for road conditions and because the added weight of thicker-walled vessels reduces the portion of the truck's gross weight that can be devoted to CO_2.

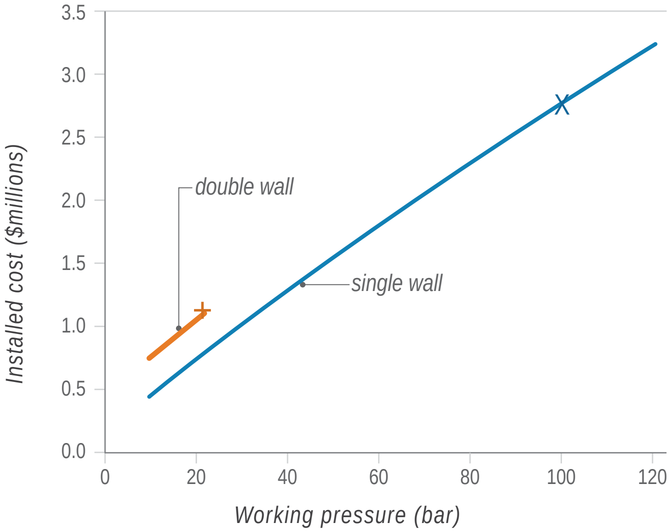


Figure 53. Estimated installed cost of a CO² storage vessel, 30 ton capacity. *"+" denotes parameters for standard refrigerated CO² conditions; "x" denotes parameters for standard compressed CO² conditions.*

There are tube trucks under development for hydrogen and compressed natural gas transport that use carbon fiber materials and multiple, smaller-diameter cylinders to transport gases at high pressure and ambient temperature. CO_2 is easier to liquefy (requires lower pressures or more moderate temperatures) than natural gas or hydrogen. These tube trucks could be used to transport compressed CO_2 as well. However, since this is an emerging technology, we focus our attention here on cryogenic CO_2 transport.

CO_2 can also be transported by rail, although this is rare; we were not able to find any published data on current practice and rely on idealized analyses and analogies to liquid propane transport. There are similar considerations in terms of compressed versus refrigerated transport, although the longer staging times required to fill a train of CO_2 cars may tip the optimum towards compressed transport in the future. For the purposes of this analysis, we assume that CO_2 by rail uses insulated tanks similar to those on trucks, and that the source-to-pipeline delivery time is short enough not to require active cooling.

Transport by Truck

Large scale electric power and carbon capture and storage projects generally depend on rail transport for solid fuel and pipeline transport for natural gas and CO_2. These are the lowest-cost options for large, centralized facilities. However, for small-scale facilities and geographically dispersed carbon sources, such as forest or agricultural residue, trucks can be very economical at some stage of the carbon chain. Any of the materials that need to be transported in the negative emissions system can be moved by truck: solid biomass, CO_2, liquid fuels, biomethane, hydrogen, et cetera. However, the costs and the capacities of the trucks vary as well as some of the labor expenses.

In general, truck transport is a commodity market with relatively stable prices. The American Transportation Research Institute conducts an annual survey of commercial trucking companies and compiles average costs of shipping in various categories [222]. In 2017, the most recent year available, the average cost of operating a tractor-trailer was $1.62 per mile in the Western region of the U.S. This was slightly lower than the national average ($1.69 per mile).

That average reflects primarily dry goods transport. Tank trucks are slightly more expensive to operate because of more expensive trailers, higher driver wages, and higher maintenance costs. The American Transportation Research Institute provides an estimate of $1.86 per mile nationally. Adjusting this value to the Western region by the same ratio as above, adding a 6% profit margin [223] to convert from producer prices to consumer prices, and converting to 2018 dollars, we assume $1.93 per mile for cryogenic CO_2 trucks, and retain $1.75 per mile for biomass transport. These values then have to be divided by the average load to estimate the unit price of transport.

The maximum weight of goods that can be carried by truck is limited by the legal gross weight limit for a typical tractor-trailer of 80,000 pounds (36.3 tons). The empty weight of the truck varies in the range of 20,000–26,000 pounds (9.1–11.8 tons), leaving at most 54,000 pounds (24.5 tons) of delivered goods [224]. However, not all loads are carried at maximum weight. The National Research Council assessed average net loads by commodity and type of truck [224]. The highest average loads were for coal (22.7 t) and gasoline (24.2 tons) commodities, and for logging trucks (22.7 tons) and bulk trucks (22.7 tons), which refers to trucks that carry unpackaged commodities, like liquids and grain. Average loads were somewhat lower for other commodities relevant to biomass transport, such as “logs and other wood in rough” (21.2 tons) and cereal grains (19.0 tons).

The size of a biomass load will generally be limited by weight or volume (as opposed to source availability or order size). A 53-foot trailer, which is the most common of the larger dry trailer sizes [222], has a volume of about 110 m^3. A study of Finnish wood chips indicated that fuel wood chips had a bulk density of 250–350 kg/m^3 [225]. The reported range of densities is fairly consistent across logging residue, whole tree chips, log chips, and softwood bark, but slightly higher for birch bark (300–400) and slightly lower for stump chips (200–300 kg/m^3). This indicates that for most sources, full loads by weight (~22 tons) are achievable. Some agricultural residues have lower bulk density, on the order of 150 kg/m^3, which would result in a less than full load, but there are options for pretreatment and compaction, such as briquetting, which achieves densities of 400–650 kg/m^3 [226]. For the purposes of analysis, we assume that biomass is trucked with an average load of 22 tons, with chipping or compaction necessary to achieve full loads performed at the collection site.

Table 31. *Key assumptions for truck transport.*

Parameter	Biomass transport	Liquid CO_2 transport
Operating Cost [$/truck-mi]	$1.75	$1.93
Average Load [t]	22	22
Transport unit cost [$/t-mi]	$0.159	$0.175
Fuel consumption [gal-diesel/truck-mi]	6	6
Fuel CO_2 emissions, 2025 [g CO_2/t-mi]	88	88
Fuel CO_2 emissions, 2045 [g CO_2/t-mi]	62	62

The maximum load of CO_2 in a cryogenic gas truck may be slightly lower than for non-pressurized goods because of the weight of the pressure tank. However, tanks with at least 22 ton capacity are available commercially [227], [174], so

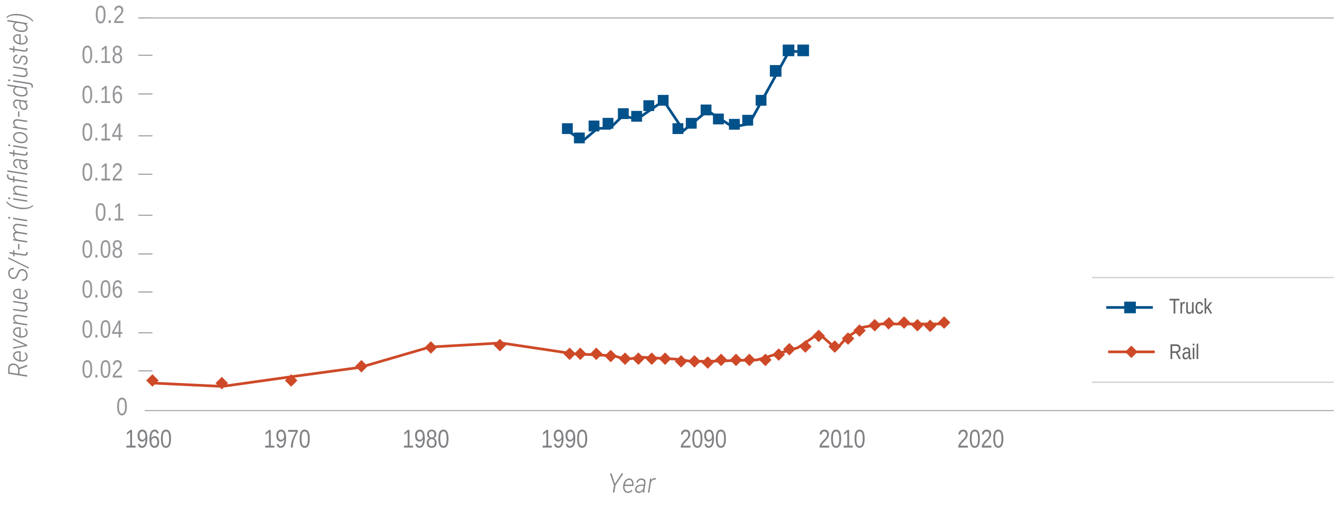


Figure 54. Historic rail and trucking freight revenue. *Converted to metric ton basis, 2018 dollars. Source: Bureau of Transportation Statistics.*

we also assume a 22 ton load for liquid CO_2. A summary of parameters and assumptions for truck transport are shown in Table 31.

Our calculated transport cost can be roughly compared with the unit cost values reported by the U.S. Department of Transportation shown in Figure 54. However, the most recent values available from this dataset are from 2009. Psarras et al., [174] estimate the cost of transporting CO_2 by truck for utilization from small sources and find somewhat lower unit costs of \$0.11–0.13 per ton of CO_2 using a process-based cost model from 2003 [228].

Transport by Rail

Biomass transport by rail is common. Woodchip and pelletized wood for energy are internationally traded commodities, although primarily in Europe [229]. In the United States, 27 million tons of lumber and wood were moved by rail in 2013 in the U.S., about 1% of total rail freight [221]. The related categories of bulk grain and coal comprised 6% and 20% of gross rail revenue that same year [230].

Freight rail actively serves 36 of the 58 counties in California (see Figure 55). Rail transport is well known to have lower cost than truck transport and a lower climate impact (we calculate 3.7 times lower) as well as lower externalities in other categories [231]. Therefore, wherever large flows of biomass must be moved more than trivial distances, and rail is practical, rail appears to be a beneficial choice. However, new facilities will not necessarily be located on existing rail lines, so construction of a local railroad spur will often be necessary to take advantage of longer-distance rail transportation. Benchmark construction costs for new rail lines are \$1–2 million per mile, which is somewhat more than pipelines [232], [231]. Building railroad spurs to service biomass processing facilities thus only makes sense for large throughput. However, for a typical gasification plant (4,500 bone dry tons of biomass per day) or pyrolysis plant (2,000 bone dry tons per day), at least tens of miles of new track would be justified by the savings in transport cost.

The average unit cost of rail transport is reported annually by the Bureau of Transportation Statistics, as shown with the trucking values in Figure 54. These data are adjusted for inflation and include profit because they are based on gross revenue. The unit cost varies by distance, load size (number of cars), and by commodity. A USDA analysis found that costs for short-haul grain transport (20–500 mi) were about 1.5 times higher than for longer hauls in 2011 [233]. A study by Argonne National Laboratory reported that short haul coal transport costs averaged about \$0.042 per ton-mi in 2007, which is about 1.7 times the economy-wide average, after adjusting for inflation [230]. For grain, the smallest loads of 1–5 cars cost 1.4 times as much as the largest loads (75+ cars).

Figure 55. Map of California counties with rail access. *Counties with active freight rail service are shaded. Green lines show exiting rail lines (some are not active). Purple ovals denote proposed CO_2 storage sites. Rail data from the U.S. Bureau of Transportation Statistics.*

Rail cars are capable of carrying about 4 times the weight of goods as a truck (75–100 tons), but only about 1.7 times the volume (150–190 cubic meters) [234]. Consequently, low-density biomass, like uncompacted woodchips, may cost more than average to transport per ton-mile. We have not evaluated whether biomass transport by rail would lead to more empty car hauls than other commodities: eastbound boxcars already run 42% of miles empty, while covered hoppers and tankers run 50% of miles empty [235].

Almost all of the biomass transported within California will fall in the short-haul category, however, loads could tend to the larger side. A 2,000-ton-per-day pyrolysis plant would process about 20–50 train cars per day of biomass, depending on bulk density and water content. Altogether, we assume that biomass by rail costs 1.6 times the national average unit cost, giving \$0.071 per ton-mi, as shown in Table 32.

CO_2 can also be moved by rail, presumably in cryogenic tanker cars similar to the trailers used for truck transport. The unit cost of CO_2 transport by rail is likely similar to other goods, except that loading and unloading a trainload of CO_2 requires a staging facility with storage capacity to collect the CO_2 between train arrivals or departures. In an analysis by U.S.-based Bright Energy, they found that CO_2 by rail is technically feasible, and yields costs that are lower than trucking and

Table 32. *Key assumptions for rail transport.*

Parameter	Biomass transport	Liquid CO_2 transport
Transport Cost	\$0.071/t-mi	\$2/t-CO_2 + \$0.071/t-CO_2-mi
Fuel CO_2 emissions, 2025 [g CO_2/t-mi]	25	25
Fuel CO_2 emissions, 2045 [g CO_2/t-mi]	18	18

competitive with small-diameter pipelines [236]. These findings are consistent with Gao et al. [235]. In one of the few quantitative assessments of CO_2 by rail that we have found, Gao et al. estimated the cost of transporting CO_2 for a case study in China. They found the levelized cost of transporting 4,000 tons of CO_2 per day on a 370 mi rail route was 77 RMB2007 (2007 Ren Min Bi), about \$13 per ton of CO_2 in 2018 U.S. dollars. This compared with 43 RMB, about \$7 per ton, for a 190 mile pipeline. The rail value included \$0.71 per ton for short pipelines to the rail stations and \$0.88 per ton for intermediate storage tanks. For purposes of our analysis, we assume that the cost of CO_2 transport by rail is \$0.071 per ton-CO_2-mi + \$2 per ton-CO_2 for staging and interconnection.

Transport by Pipeline

Pipeline has been the mode of choice for large-scale transport of CO_2. There are 4,500 miles of CO_2 pipeline in the U.S., covering 50 different projects, mostly for enhanced oil recovery [237]. These pipelines have proved to be safe and cost-effective. For pipeline transport, CO_2 is compressed to a dense phase at 80–150 bar and ambient temperature. A compression station at the start of the pipeline (or multiple stations along the length of longer pipelines) provide the energy to move the CO_2 through. Pipeline construction and operation borrow closely from the much larger experience with natural gas pipelines, but the pressures are higher for CO_2, so natural gas lines cannot be used directly.

The National Energy Technology Laboratory has recently created a spreadsheet-based model for estimating the cost of CO_2 transport by pipeline [238]. The National Energy Technology Laboratory model implements several models from the literature, including McCoy and Rubin [2008] and Parker et al., [2004]. The model incorporates price data from natural gas pipeline construction delineated into five U.S. regions. Given a CO_2 flowrate and length, the model will calculate the pipeline diameter and number of pumping stations yielding the lowest levelized cost and report that cost. The model incorporates detailed financial parameters, such as different interest on debt and equity, discount schedules for the construction period and future maintenance costs, and explicit taxes. The default parameters are chosen to be reasonable for a carbon capture and storage or enhanced oil recovery project.

Comparing the National Energy Technology Laboratory model outputs to real pipeline projects, the authors found that the McCoy and Rubin method and the Parker et al. method yielded estimates closest to the real costs, with the former tending to underestimate costs, while the latter overestimated costs [238]. Thus, we consider the estimates generated by the two methods to be the upper and lower bound estimates on pipeline transport costs.

As a note of caution, there are currently no major CO_2 pipelines in California. In particular, industry experts have expressed concern about the costs and legal difficulties of obtaining rights-of-way for new pipelines in California. One power company shared that running CO_2 pipelines on existing natural gas rights-of-way requires renegotiating with the landowners because CO_2 pipelines are higher pressure and thus are not covered by existing agreements. Although the National Energy Technology Laboratory model cost basis is regionally specific and includes natural gas pipeline construction indices from California, the Western region spans a large area, including Oregon, Washington, Idaho, Nevada, and Arizona. In most of the model results, rights-of-way are a small fraction of the total cost, but there could be local challenges. Therefore, we will consider scenarios with a minimum need for new pipelines, although a central trunk line will almost certainly be valuable for large-scale transport.

For purposes of our analysis, we use the pipeline cost estimates provided by the National Energy Technology Laboratory model, taking the mean of the McCoy and Rubin and Parker et al. methods. We use the Western region, and take the break-even, levelized CO_2 costs at the year CO_2 pumping begins (three years after construction begins), adjusted to 2018 dollars. We leave other parameters at their defaults. In the scenarios we consider, the results range from 0.004 to 0.61 \$/ton-mi of CO_2. These will be discussed in more detail below.

Comparing Transport Options

The best choice of transport method for a given carbon source depends on several factors: distance, size of source (flowrate), and proximity to rail and pipeline networks. Here we look at different source types and consider some example scenarios in order to build reasonable system-wide scenarios that are best for the economics of CO_2 movement. We do not attempt to evaluate the impacts of other important issues such as criteria pollutants and noise.

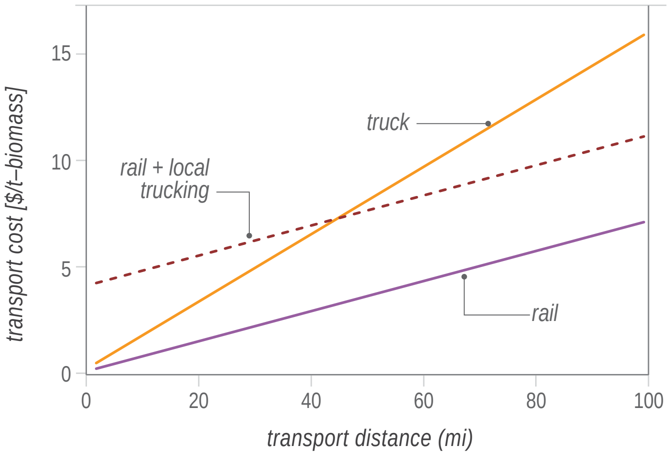


Figure 56. *Cost to transport biomass vs distance for truck and rail. The dashed line represents the cost of first trucking locally (23 mi) to a rail station and via rail from there, where distance is only counted from the rail station.*

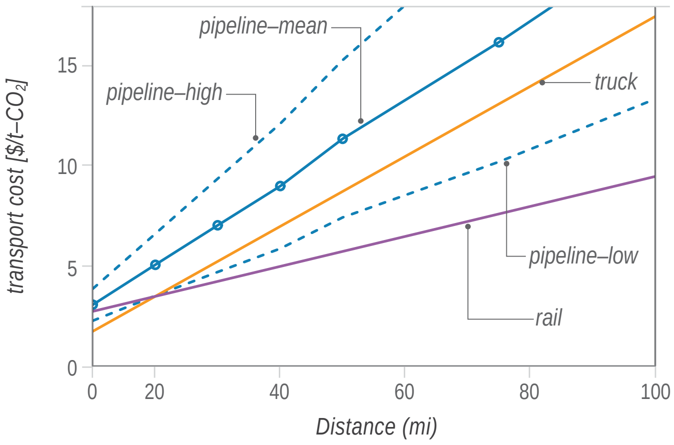


Figure 58. *Transport cost of CO_2 versus distance for three modes for a CO_2 flowrate of 580 tons per day (typical pyrolysis plant).*

When transporting solid biomass, rail is often the most economical. Figure 56 shows the estimated transport cost for truck and rail as a function of distance. For similar transport distances, rail is preferred wherever it is available. This figure does not show the effect of flowrate, but trucking cost is basically constant with flowrate, as long as the source can supply a full truckload (which all the sources we consider can). The rail price varies only slightly with flowrate. Even for a single railcar load, the unit price is less than half that for a truck. However, rail is not always available near the source, and even if a rail line is nearby, building a rail spur to the source may not be practical or cost effective. Biomass can be trucked from the source to a transfer station, but for short distances using the truck alone may be preferred. Figure 56 shows that, even with added trucking to a transfer station, rail is preferred for distances longer than about 45 mi. For purposes of analysis, we assume that intra-county movement of biomass is by truck and inter-county movement is by rail when available and less costly.

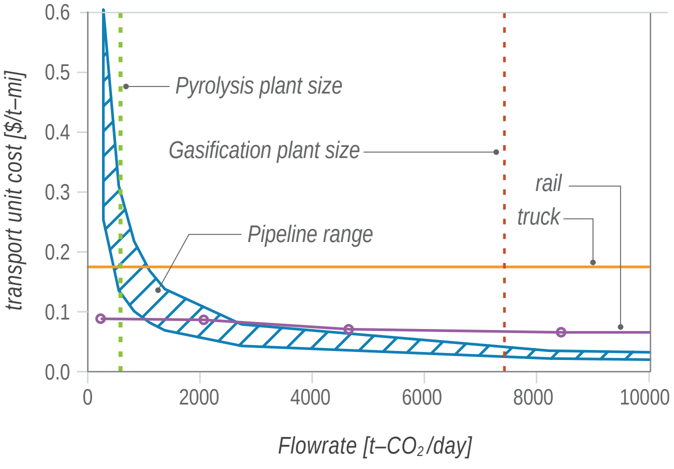


Figure 57. *Unit cost to transport CO_2 by three modes over 150 mi. Vertical dashed lines mark the calculated CO_2 capture rates at typical pyrolysis and gasification plants.*

The picture for transporting CO_2 is more complicated than for biomass. Figure 57 shows the estimated cost for the three modes of transport for a distance of 150 mi. The pipeline cost depends strongly on flowrate. The slight variation of rail cost on flowrate is also shown, here assuming the train runs once per day. At large flowrates, like the size of a typical gasification plant, a pipeline is clearly the lowest cost option. Rail becomes competitive with a pipeline below about 2,000 tons of CO_2/day to the point where rail is most likely the preferred option for flows typical of a pyrolysis to liquid fuels plant. Rail always dominates the trucking option over this distance, though our assumptions about rail cost (the fixed costs of CO_2 staging and storage at either end) break down at very small flowrates.

Figure 58 shows the effect of distance on CO_2 transport cost at a flowrate of 580 tons of CO_2 per day, which is the rate we calculate for a pyrolysis plant processing 2,000 bone dry tons per day of biomass for liquid fuel. At this throughput, truck, rail, and perhaps pipeline transport are competitive at shorter distances. Above about 25 mi, rail probably dominates the other options.

Figure 59 shows the effect of distance on transport cost for a flow of 7,400 tons of CO_2/day (a typical gasification to

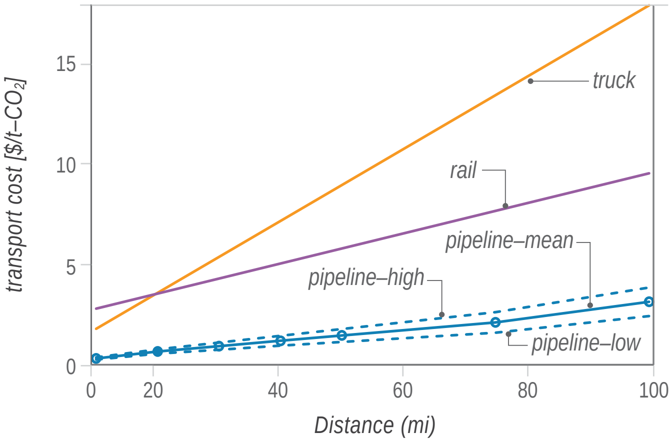


Figure 59. *Transport cost of CO_2 versus distance for three modes for a CO_2 flowrate of 7400 tons per day (typical gasification plant).*

hydrogen plant). At this flowrate, the pipeline dominates at every distance. If a pipeline right-of-way is not available, rail is mostly favored. Because of the fixed costs of CO_2 storage facilities and short pipeline connections at either end of the rail route, trucking appears to be less costly than rail at very short distances, however this option is probably not realistic; about 340 truckloads/day would be required to sustain this flowrate. There is a strong incentive to site gasification plants where pipeline access is feasible.

Figure 60. *Map of potential CO_2 trunk pipeline. California counties are shown with existing major natural gas pipelines in orange. Approximate proposed CO_2 storage areas are marked with purple ovals. The base case CO_2 pipeline is shown in red. This route follows major natural gas pipelines and passes through our studied storage sites in the central valley, and a potential geothermal-powered direct air capture plant near the Salton Sea.*

Routing and Distances

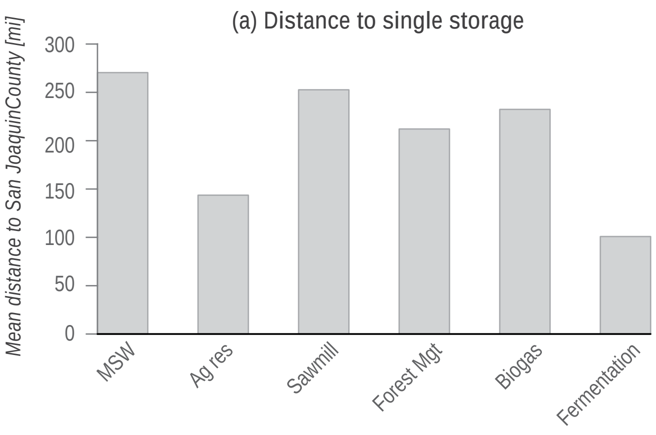
To estimate the travel distances for all the relevant pathways, we use a county-level system model. As described in Chapter 3, we have estimates of biomass availability and existing biogas facility locations in each of California's 58 counties. Using geographic information system software (QGIS v. 2.18), we calculated the geometric centroid of each county and used that to approximate transport distances. Since our biomass data is by county, we do not know exact locations of biomass sources, or practical locations for processing plants.

Using the Open Source Routing Machine [239] and map data from Open Street Map, we snapped each centroid to the nearest road. We then queried and recorded the shortest-trip road distance between every pair of county centroids. These values serve as the inter-county distances for road transport. Of course, some of California's counties are quite large and, in reality, many trips from the near side of one county to the near side of another, or from the far side to far side, will deviate substantially from the centroid-to-centroid distance. However, most carbon sources are spread over a large area, so these deviations will tend to average out. The centroid-to-centroid distance is an approximation of the average of many any-point-to-any-point trips from one county to another, so it is representative of the features associated with a more precise plan.

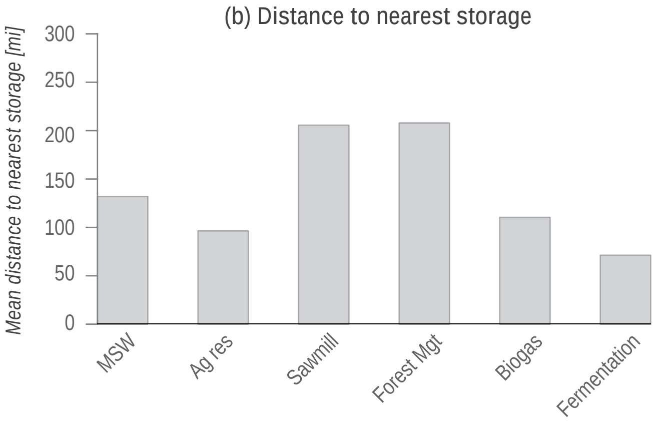
To calculate an average transport distance within a county, we use the county area, A. The average distance between two random points in a square is $0.52\sqrt{A}$ [240]. On the one hand, the road distance will be longer than the geometric distance between a given carbon source and conversion facility or transport hub. On the other hand, these facilities are likely to be sited to reduce transport cost, giving better-than-random trip lengths. On balance, we use $0.5\sqrt{A}$ as the distance for intra-county transport of biomass. Across California, the average intra-county distance is 23 mi.

The weighted-average road distance from biomass in each county to a single storage site in San Joaquin County is shown in Figure 61a. Figure 61b shows the distances to the nearest of our two studied storage sites, in San Joaquin and Kern Counties. Moving to two storage sites, the average transport distance is reduced by a third. Now consider a scenario with a CO_2 trunk line as pictured in Figure 59. This route follows one of the largest-gauge natural gas pipelines through the Central Valley and connects to the two storage sites and a proposed

(a) Distance to single storage



(b) Distance to nearest storage



(c) Distance to nearest pipeline

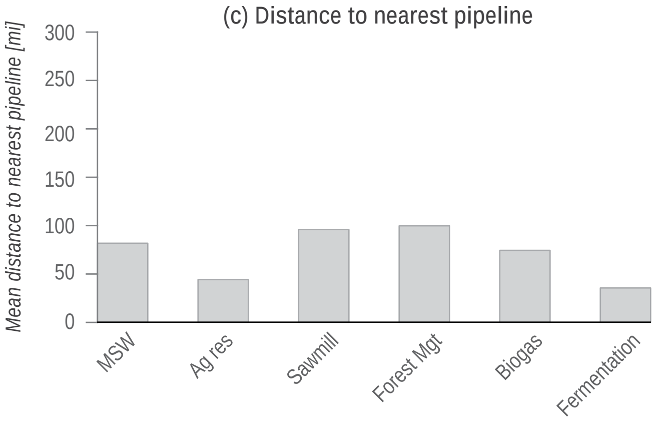


Figure 61. *Average calculated road distance to storage for each biomass type: (a) distance to a single storage site in San Joaquin County; (b) distance to nearest of two storage sites in San Joaquin and Kern Counties; and (c) distance to nearest pipeline county as defined in the previous figure. Category labels refer to the following: MSW: Municipal Solid Waste; Ag Res.: Agricultural Residue; Sawmill: Sawmill residue, shrub and chaparral; Fermentation: CO_2 from fuel ethanol and beverage fermentation.*

geothermal direct air capture plant on the Salton Sea. The pipeline route primarily runs through rural and agricultural areas, similar to where most CO_2 pipelines have been built elsewhere in the United States, and covers a large portion of the state without crossing through the mountainous or densely urbanized regions. This is our baseline pipeline scenario. The average distance to the nearest pipeline is shown in Figure 61c. Here, the global average distance is reduced by about half from the two-site case in Figure 61b. These are the values shown in Table 35 and used for the following analysis. The average intra-county distance in Table 35 is the average of all counties, weighted by biomass availability of the type indicated.

Transport Cost Model

The above figures suggest the optimal modes for biomass or CO_2 transport when the flowrate is fixed and the travel distance for the modes are comparable. However, this is often not the case. Rail access or pipeline access may be regionally limited for practical reasons, even when they are economically preferred, which can lead to a choice between a direct truck route or an indirect multi-modal route. In many cases there is a tradeoff between siting a conversion facility near the carbon source and transporting CO_2 to the storage site or siting the conversion facility near the storage site and transporting the biomass. The different conversion technologies generate different quantities of CO_2 per unit biomass, which makes this trade-off dependent on the conversion technology chosen. Similarly, the different biomass types have different water contents, for example forest woodchips typically contain about 30% water, while dry organic municipal solid waste has about 10%. Woodchips are thus more expensive to transport than municipal solid waste relative to the CO_2 they generate if the same conversion technology is used.

We created a county-level model that estimates the cost of carbon transport for five different transport scenarios across six categories of carbon sources. We focus here on three conversion technologies for dry biomass, which represent the lowest-cost options for generating three energy co-products: gasification to hydrogen, pyrolysis to liquid fuel, and combustion to electricity. For biogas, we choose the lowest-cost technology pathway: combustion for electricity at a central power plant retrofit with CO_2 capture while also capturing CO_2 locally from biogas upgrading. Transport of CO_2 from a geothermal direct air capture plant is included as well.

Table 33 summarizes the cost basis for each of the five transport modes. Each mode represents a full chain from carbon source to (optional) conversion, to CO_2 injection,

Table 33. *Summary of transport cost model: cost basis by leg of trip, mode of transport, and technology. Cells with one value apply to all conversion technologies. Others are marked as follows:* a) Value for pyrolysis; b) Value for gasification and combustion; c) Value for biogas recovery and fermentation CO_2.

Name of leg	Local Trucking at Origin	Pipeline spur at origin	Inter-county transport	Pipeline spur at destination
Distance	by county (3-70 mi)	20 mi	by county (0-560 mi)	20 mi
Biomass by Truck	–	–	$0.159/t-mi	\$5.38/ton-CO_2^{a} \$0.684/ton-CO_2^{b} 0^{c}
CO_2 by Truck	\$0.159/ton-m^{ia,b} 0	–	\$0.175/t-CO_2-mi	–
Biomass by Rail	$0.159/t-mi	–	$0.071/t-mi	\$5.38/ton-CO_2^{a} \$0.684/ton-CO_2^{b} 0^{c}
CO_2 by Rail	\$0.159/ton-m^{ia,b} \$0.175/ton-mi^{c}	\$5.38/ton-CO_2^{a} \$0.684/ton-CO_2^{b} 0^{c}	0.071/t-CO_2-mi	\$1/t-CO_2
CO_2 by Pipeline	\$0.159/ton-m^{ia,b} \$0.175/ton-mi^{c}	\$5.38/ton-CO_2^{a} \$0.684/ton-CO_2^{b} 0^{c}	by county	–

either at a geologic storage site or to a trunk pipeline connected to a storage site. The system-level cost of the trunk line is calculated separately. For the cases of pyrolysis, gasification, and combustion, where the plant location has yet to be chosen, we assume the plant is placed in the same county as the biomass source (to minimize biomass transport), or in a county with a CO_2 pipeline, to minimize CO_2 transport cost.

For simplicity, we do not consider placement of conversion facilities in intermediate locations. With a sophisticated optimization, one may find value in establishing conversion hubs in locations between sources and sinks in order to consolidate CO_2 flows and capture the savings of a large pipeline. However, we expect the difference from those scenarios to be relatively minor.

There are up to four legs of transport, which are summed to give the total cost for each mode. The transport modes are shown schematically in Figure 62. They are as follows:

- **Biomass by truck:** After collection to the roadside (the cost of which is covered in Chapter 3), biomass is picked up by truck and hauled to a plant near the CO_2 storage site. The resulting CO_2 captured from the plant travels via short pipeline spur to either a storage well or a CO_2 trunk line. For a pyrolysis plant, this last spur could be accomplished via truck or rail at similar cost, but for simplicity we label this a pipeline for both types of plant.
- **CO_2 by truck:** After collection at the roadside, biomass is trucked to a local conversion facility (within the same county, in model terms). From there, tanker trucks carry the resulting CO_2 for (usually) a longer distance to a storage site or pipeline injection point. For biogas sources, there is no local trucking of biomass, so only the tanker truck leg is counted.
- **Biomass by rail:** Biomass is first trucked from roadside collection points to a local rail station. From there it travels a longer distance to the conversion facility, which sits on a rail line. After conversion, the resulting CO_2 is carried to a trunk line via a short pipeline spur.
- **CO_2 by rail:** Biomass is trucked from the roadside to a local conversion facility. The resulting CO_2 is carried via short pipeline spur to a local rail station with a CO_2 staging facility. From a direct air capture plant, CO_2 is also carried here by pipeline spur. For biogas sources, CO_2 is carried by tanker truck to the rail station. There, tanker railcars are periodically filled with CO_2 and make their way to a rail station near a storage site with a similar CO_2 staging facility. From the destination station, CO_2 is carried by short pipeline spur to a geologic storage well or CO_2 trunk line.

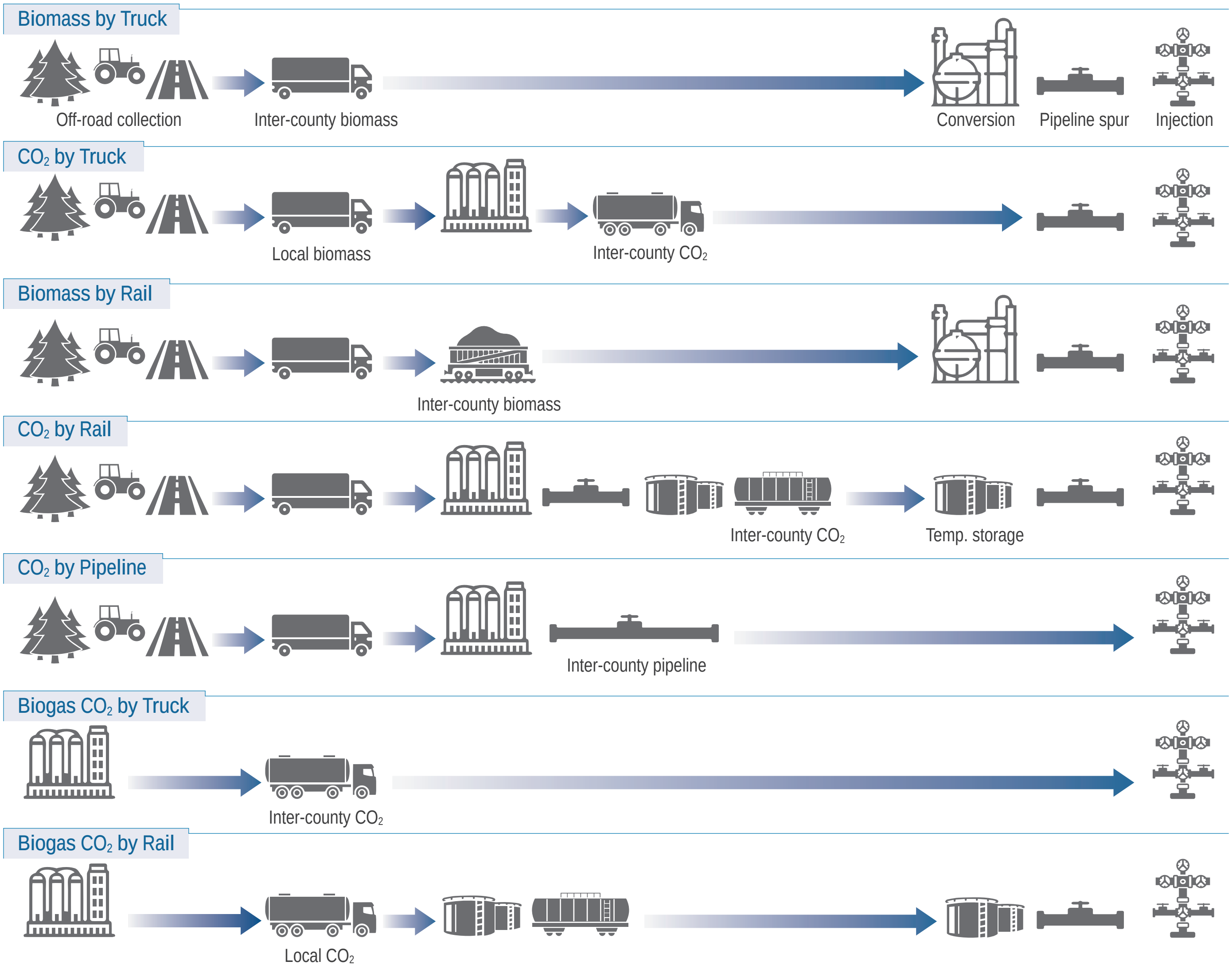


Figure 62. *Diagram of transport pathways.*

- **CO_2 by pipeline:** Biomass is again trucked from the roadside to a local conversion facility. The resulting CO_2 is carried first by short pipeline spur and then consolidated, at least at the county level, for a longer run to a geologic storage facility or larger trunk line. Alternately, CO_2 from biogas recovery is trucked to the local consolidation point.

Our carbon source categories are expressed as either bone dry metric tons of biomass or as dry metric tons of gas. We use several mass conversions factors to convert the source quantities into mass of material transported, and later to a negative emissions basis for common comparison. The technology-dependent conversion factors are summarized in Table 34 while the source-dependent conversion factors are summarized in Table 35. Table 35 also shows several characteristic values for each source type: the weighted-average distance to the nearest storage site or pipeline county (as calculated by the distance model described below), the weighted-average local (intra-county) transport distance (also described below), a characteristic CO_2 flowrate, which is based very roughly on the quantity of the biomass in major source counties and the size of the applicable conversion facilities, and the characteristic pipeline transport cost. The intra-county distance for municipal solid waste is neglected because local collection of municipal solid waste is already performed for waste management. The pipeline cost is calculated for the characteristic flowrate and distance to storage shown. Other than the water content, the values in Table 35 are used in the scoping analysis to help select between transport modes, but not in the system-level cost estimates described later in this chapter.

Combining the parameters from Table 33—Table 35, we calculate the cost of transport for each pathway as follows:

Equation 4. *Cost of Transport*

$$T_{C,rem} = \left[\sum_{i\ legs} f_{mat} U_i d_i \right] \frac{1}{f_{rem}}$$

where $T_{C,rem}$ is the total transport cost per ton of CO_2 removed from the atmosphere, U_i is the unit cost for leg i, which is also a function of the technology and mode of transport, f_{mat} is the conversion factor for the material being carried in leg i, based on either the first column of Table 34 or Table 35, d_i is the distance for leg i, which is also a function of the biomass type, and f_{rem} is from the third column of Table 34.

In this model, the cost of CO_2 transport for a given negative emissions pathway varies by county and also by system-level decisions, including where the conversion facilities are sited, which counties have access to a CO_2 pipelines and, crucially, how many other sources are sharing the pipeline. We'll first look at characteristic scenarios for each of the biomass source types and then use those results to inform the parameters of system-level scenarios to give base-case transport costs. To fairly compare unit costs across modes and technologies, we need a characteristic distance, which most strongly impacts the cost of rail, and a CO_2 flowrate, which most strongly impacts the cost of pipeline transport.

Table 34. Mass conversion factors for transport model. *For each conversion technology, these factors show the quantity of CO_2 transported in the model, removed from the atmosphere, or removed and avoided, respectively, for each ton of dry biomass input. For pyrolysis, the transported CO_2 is less than the removed CO_2 because some CO_2 is removed via biochar, which is spread locally. Avoided emissions are the emissions from fossil fuels that are displaced by the fuel produced in the scenario. "Pyrolysis – forest" refers to both Forest Management and Sawmill Residue, Shrub, and Chaparral categories, while Ag refers to Agricultural Residue.*

	Captured ton CO_2 / BDT source	Removed ton CO_2 / BDT source	Removed + avoided ton CO_2 / BDT source
Pyrolysis – forest	0.294	0.494	1.48
Pyrolysis – Ag	0.296	0.496	1.33
Gasification to H_2	1.65	1.65	2.91
Combustion to electricity	1.55	1.55	1.55
Biogas recovery	0.67	1.37	1.37
Fermentation CO_2 recovery	1	1	1
Geothermal DAC	1	1	1

BDT = bone dry tons, DAC = direct air capture

Table 35. *Water content and characteristic parameters by carbon source.*

	Water Content	Avg Distance to storage [mi]	Avg intra-county distance	Characteristic Pipeline Flow [Mt-CO_2/yr]	Pipeline Unit Cost [\$/t-CO_2-mi]
MSW	10%	82	0	1.5	0.050
Ag residue	25%	44	28	1.5	0.051
Sawmill residue, shrub, and chaparral	30%	96	33	1.5	0.050
Forestry Management	30%	100	28	1.5	0.050
Biogas	0%	74	28	0.2	0.242
Fermentation	0%	36	28	0.2	0.242
DAC – Salton Sea	0%	320	0	20	0.0164

Mt-CO_2 = million tons of CO_2, MSW = municipal solid waste, DAC = direct air capture

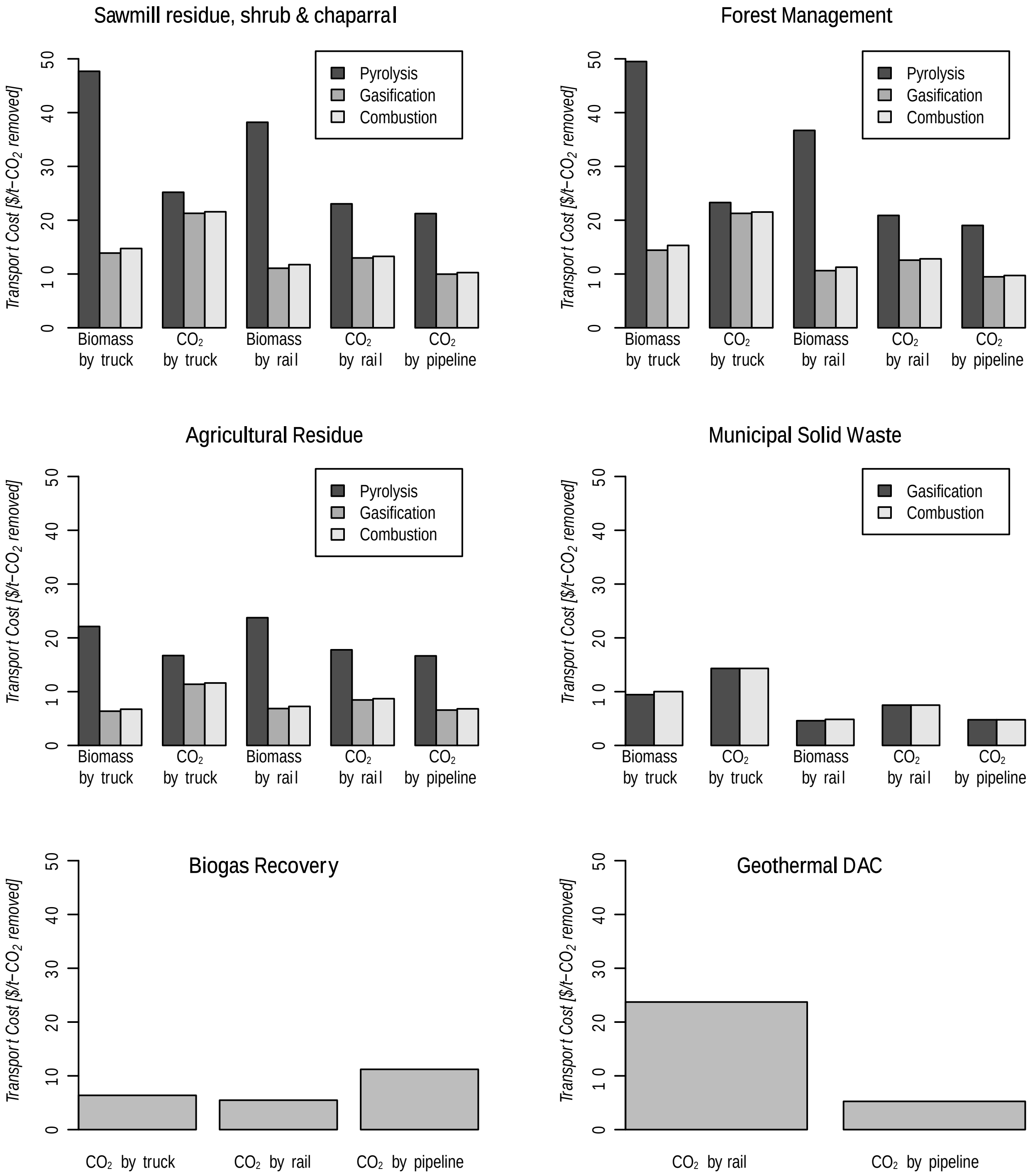


Figure 63. *Characteristic transport costs per ton of CO_2 removed by mode, technology, and carbon source type.*

Figure 63 shows the estimated costs for the characteristic scenarios of each carbon source type. While the transport cost is different for each county and depends on some system-wide decisions, we've calculated costs for these average distances and characteristic flowrates to draw some general conclusions about relative cost and mode choice.

First, consider the pyrolysis technology in a location where only trucking is available. Across biomass types, we would prefer to build the plant near the source of biomass and transport the CO_2. This is primarily because, for pyrolysis, the volume of CO_2 to transport is much lower than the input of biomass on a mass basis. If rail is available, then the preference holds and CO_2 by rail is the lowest-cost option among the four. However, when transporting agricultural residue, because of the shorter average distance to a pipeline, the difference between CO_2 by truck and by rail is very slight, so we are basically indifferent between these options. If a pipeline can be constructed, that would be the best option for all biomass types. However, this assumes a flow of about three pyrolysis plants from the given county.

For gasification via truck or rail, the situation is reversed. Because the mass of CO_2 resulting from gasification is larger and more expensive to transport than the input biomass, we would rather transport the biomass and site the gasification facilities at the storage location or trunk pipeline. If a pipeline can be constructed, it is very slightly preferred, but we are basically indifferent between biomass by rail and CO_2 by pipeline. This assumes that the pipeline only carries one plant's worth of CO_2. If multiple CO_2 flows are combined, a pipeline would quickly become a better option.

For biogas recovery, the characteristic flow is relatively small from most counties. Only Los Angeles County could sustain a pipeline flow near or above 1 million tons CO_2 per year. For most other counties, a pipeline dedicated to CO_2 from biogas would be more costly than transporting the CO_2 by truck or by rail.

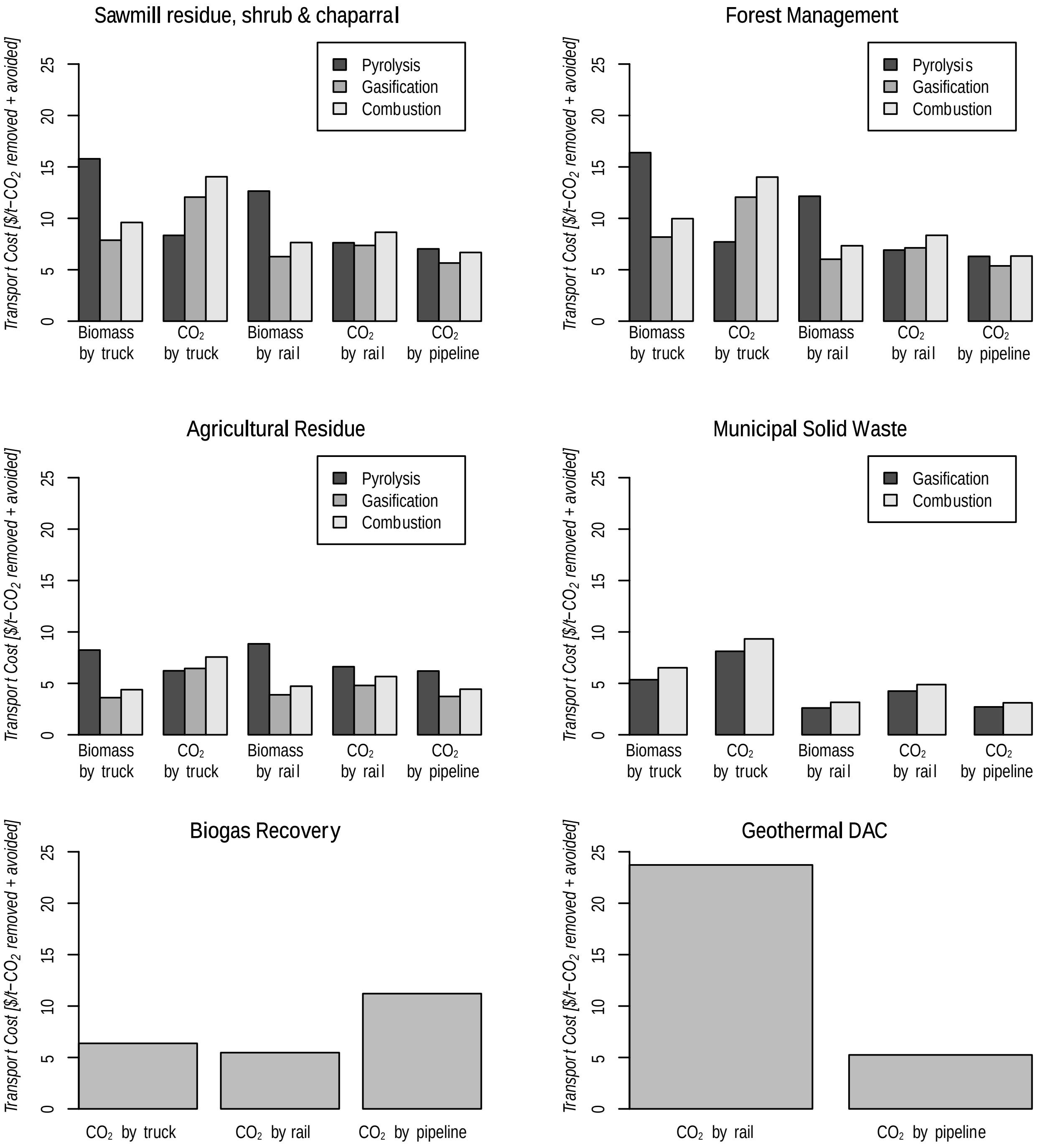


Figure 64. *Characteristic transport costs per ton of CO_2 removed or avoided by mode, technology, and carbon source type.*

Finally, we can see that a pipeline is strongly preferred for CO_2 from an example geothermal-driven direct air capture plant at the Salton Sea. At our estimated flowrate of 11 million tons of CO_2 per year, the pipeline has a substantial economy of scale advantage over rail. It's worth noting, however, that an active rail line passes directly by the existing geothermal plants. If the direct air capture plant is built in stages or the plant is built faster than the pipeline can be installed, rail is a viable transitional option.

These results are all normalized to the net negative emissions achieved (CO_2 removed) in the technology pathway. If we include avoided emissions, the transport costs are somewhat lower. Figure 64 shows all the same costs on a removed + avoided CO_2 basis. Since pyrolysis produces liquid fuel, it has a relatively larger avoided emissions benefit than gasification. All the same trends hold in Figure 64 for a given conversion technology, however pyrolysis is much more competitive with gasification and combustion on an avoided emissions basis, in terms of transport cost.

System-Wide Transport Cost

With the above trends in mind, we constructed three system-wide scenarios to estimate total transport costs. The results will be added to the technology costs in previous chapters to appear in the negative and avoided emissions supply curves in Chapter 9.

The first scenario, labeled "Gasification priority," makes maximum use of gasification-to-hydrogen technology. All the applicable biomass in each county is first moved by either truck or rail—depending on which is cheaper and whether rail is available—to the nearest pipeline county. After complete allocation, if there is not enough biomass in a destination county, it is removed from the possible destinations and all biomass is re-allocated. It turns out that every county with a pipeline receives enough biomass to support at least one gasification plant except Glenn and Merced. Meanwhile, CO_2 from biogas recovery and fermentation is transported by either truck or rail to the nearest pipeline county.

To calculate the cost of the CO_2 trunk pipelines, the flows of CO_2 injected into the pipeline in each county are compiled. The cost of each segment is calculated based on the flow in that segment, using an approximation to the NETL pipeline cost model, shown in Figure 65.

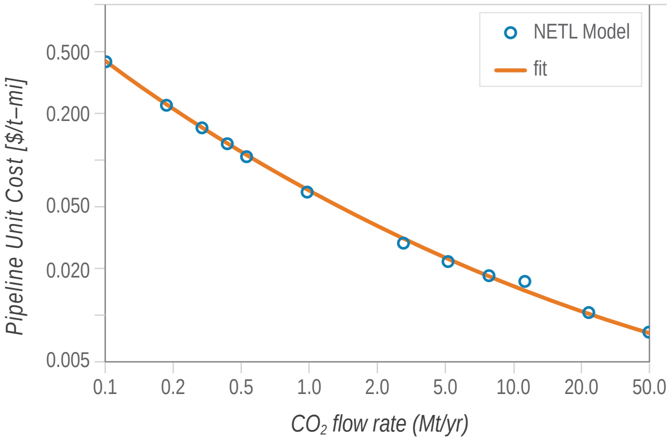


Figure 65. *Pipeline cost model and fitted equation. NETL model is from reference [238] The fitted function is:*

Cost = 0.0269 × Flowrate $^{-1.1004}$ *+ 0.0345 × Flowrate* $^{-0.4138}$ *in the units shown.*

In the second scenario, Pyrolysis priority, we allocate biomass from agricultural and forest sources to pyrolysis. Any county with at least 0.4 million bone dry tons per year in total is assumed to use pyrolysis and the resulting CO_2 is sent to the nearest pipeline county by the lower-cost mode. Counties with less than 0.4 million bone dry tons per year send biomass to the nearest pipeline county, where it is assumed a pyrolysis plant there will aggregate biomass sources. Municipal solid waste sources are still allocated to gasification because pyrolysis does not generally apply to this source type. In this scenario, only a few counties can support gasification plants because the total feedstock volume is lower, so the municipal solid waste transport cost is slightly higher than for the first scenario, even though the technology is the same.

In the third scenario, Combustion priority, we use all the carbon source categories (except fermentation and direct air capture) to generate electricity. Biomass-fired power plants are the same size (4500 bone dry tons per day input) as gasification plants, and have very similar mass conversion factors (CO_2 removed via combustion is slightly lower because we assume 90% of input carbon is captured instead of the nearly 100% during gasification to hydrogen). The routing of biomass and location of plants in the combustion scenario is thus identical to the Gasification priority scenario.

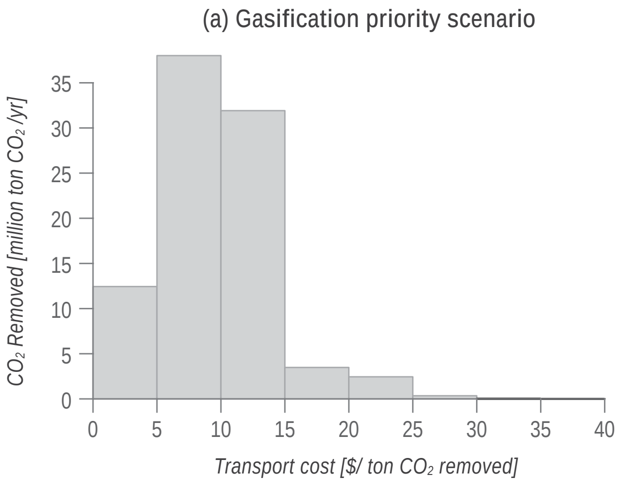
The distributions of resulting costs for each scenario are shown in Figure 66. The system-wide average transport cost is $9.80 per ton CO_2 removed for the Gasification priority scenario, $18.20 per ton CO_2 removed for the Pyrolysis priority scenario, and $10.30 per ton CO_2 removed for the

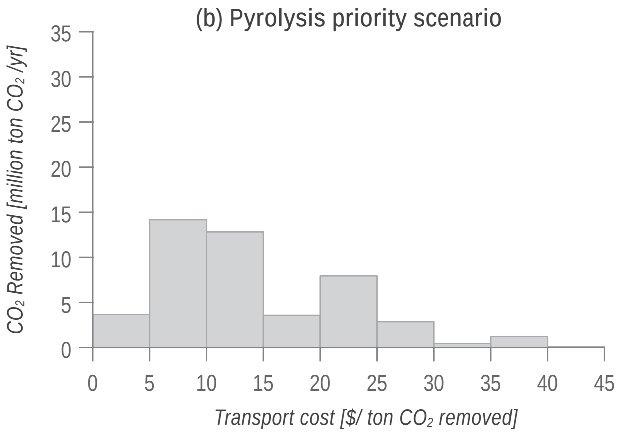
Combustion priority scenario. These averages do not include Geothermal direct air capture, which is \$5.25 per ton-CO_2 in all scenarios. The resulting parameters of the CO_2 trunk pipeline are shown for the Gasification priority scenario in Table 36. Corresponding tables for the Pyrolysis and Combustion priority scenarios are shown in Appendix G.

Overall, we find that the costs of transport in our scenarios are modest compared to the total costs of CO_2 removal. Transport costs are about twice as high in the Pyrolysis scenario primarily because less CO_2 is ultimately removed per ton of material transported. On a combined avoided and removed CO_2 basis, the transport costs are more similar, but the smaller size of pyrolysis plants also impacts the transport costs, because they cannot take as much advantage of pipeline economies of scale.

In a poorly-executed transport system that makes much less use of a CO_2 trunk line and rail, it is certainly possible for transport to be two to four times as expensive. The need for some major CO_2 pipelines is clear. But with a reasonable pipeline strategy in the Central Valley and making use of the existing rail network, the transport and logistics of a negative emissions system appear manageable. Table 37 shows the system-wide freight volumes and fuel greenhouse gas emissions from transport. We can see that trucking demand amounts to about 3—4% of projected within-state truck traffic in 2045. Rail traffic is similar in total ton-mi but amounts to a larger share, up to 20% of projected total rail volume in the state. The greenhouse gas impacts of transport are small and comprise much less than 1% of the CO_2 removed by the system.

The results from this chapter are distilled into average transport costs for each technology pathway and scenario to form a part of the basis for the total cost curves in Chapter 9.


(a) Gasification priority scenario


(b) Pyrolysis priority scenario

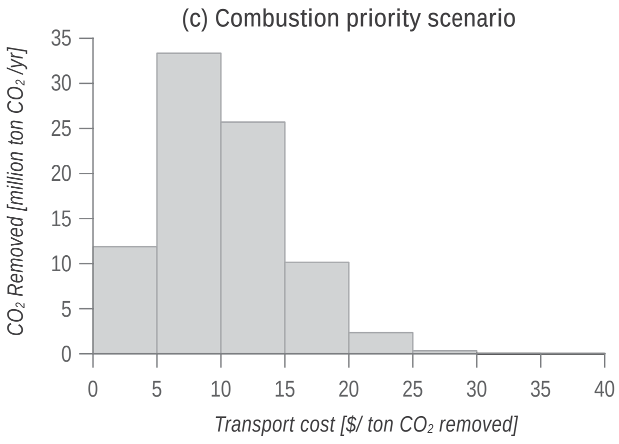

(c) Combustion priority scenario

Figure 66. *System-wide distribution of transportation costs. Includes all counties and biomass types; does not include Direct Air Capture. (a) Costs for Gasification scenario. (b) costs for Pyrolysis scenario, (c) costs for Combustion scenario.*

Table 36. *System-level pipeline characteristics for gasification scenario.*

Segment label	Origin	Destination	Distance [mi]	Flowrate [Mt CO_2/yr]	Unit Cost [\$/t-CO_2-mi]	System Cost [\$M/yr]
North Valley	Tehama	Glenn	55	22	0.0106	13
North Valley	Glenn	Colusa	28	22	0.0106	6
North Valley	Colusa	Yolo	50	30	0.0091	14
North Valley	Yolo	Sacramento	43	34	0.0086	12
North Valley	Sacramento	San Joaquin	37	39	0.0081	11
Central—North	Madera	Merced	39	2.9	0.0309	3.5
Central—North	Merced	Stanislaus	41	3.1	0.0295	3.7
Central—North	Stanislaus	San Joaquin	41	8.2	0.0171	5.7
Central—South	Fresno	Kings	33	10	0.0158	5
Central—South	Kings	Kern	73	9.6	0.0158	11.0
Salton Sea Spur	Imperial	Riverside	83	3.0	0.0297	7
Salton Sea Spur	Riverside	San Bernardino	128	7	0.0181	17
Salton Sea Spur	San Bernardino	Kern	176	10	0.0156	27
Total			**826**			**137**

Table 37. *System-wide impacts of transport for CO_2 removal. Total freight volumes are adapted from Oak Ridge National Laboratory's Freight Analysis Framework (2015). The 2045 values are about 25% higher than 2018 values. Trucking total volume is for within-state trips only. Rail total volume is the sum of within-state rail trips, 10% of ton-mi originating in California, and 10% of ton-mi destined for California from other states.*

	Trucking volume		Rail freight volume		GHG emissions from transport
Scenario	billion ton-mi/yr	% of 2045 volume	billion ton-mi/yr	% of 2045 volume	million ton CO_2e/yr
Gasification priority	3.22	3.6%	3.42	20%	0.27
Pyrolysis priority	2.61	2.9%	2.24	13%	0.21
Combustion priority	3.22	3.6%	3.42	20%	0.27

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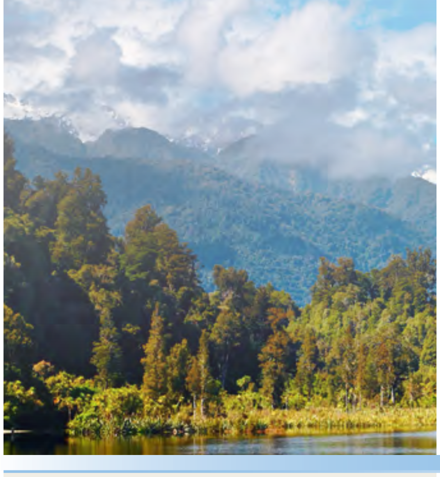
CHAPTER 8

Technology Learning and Cost Reduction



SUMMARY

Waste biomass conversion and direct air capture (described in Chapters 3-5), two pillars of our negative emissions approach, will require a broad range of technologies. While some of these technologies are mature, others are in early development and likely to be far more expensive today than they will be at maturity. Learning is a critical aspect of reducing the cost of new technologies, which requires deployment in the field.

We assess how capital costs may change with learning for two types of direct air capture technologies and for pyrolysis to liquid fuels. These technologies are important to negative emissions and well-poised for cost reductions. Other technologies in this report will also benefit from learning, but less dramatically because they are more mature or include mature component processes.

For the selected technologies, we develop simple model projections for how they will be deployed between 2025 and 2045 — globally and within California. We model scenarios of fast and slow learning to estimate the cost of future deployment, using historical precedent to establish a realistic range of learning rates for each technology. Together, these factors allow us to forecast the reduction in capital cost as a function of deployed capacity.

Key Findings

Direct air capture can benefit significantly from learning from new deployments. Modular, solid-sorbent direct air capture systems can experience a higher rate of learning than large-scale liquid-solvent direct air capture systems. We only assume deployment of geothermal-powered technology in California, and the scale of its deployment is limited to new geothermal heat flows available, giving 11 million tons of CO_2 per year. Averaging the fast and slow learning scenarios, we predict the average cost of the fleet of deployed geothermal direct air capture facilities to be \$182 per ton of CO_2.

The cost reduction for liquid-solvent direct air capture systems is dependent on amount deployed in California and globally. We assume a conservative global deployment scenario and moderate average learning rate and about 30 million tons of global deployment, leading to an average cost of deployed liquid-solvent direct air capture facilities at \$190 per ton of CO_2.

For deployment of fast pyrolysis in California, we calculate that the capital cost of the pyrolysis unit falls between 45% and 79%, for a total deployed capacity of 100,000 tons of biomass per day. This results in a 20% decrease in the capital cost for a pyrolysis to liquid fuels system. Additional global deployment would result in further decreases in cost.

Scope of Chapter

Effects of technology learning and estimates of future cost reductions for key negative emissions technologies. We describe factors affecting historical learning rates for other technologies and how learning, and associated capital cost reductions, can be accelerated. We assess learning for three technologies that are likely to benefit the most:

- geothermal direct air capture
- natural gas-powered direct air capture
- fast pyrolysis of biomass to liquid fuels

For these, we forecast capital cost reductions based upon learning rate and amount of deployment.

Introduction

The two major subcategories of direct air capture technology are quite different, and their costs and likely maturation pathways differ markedly (Chapter 5). High-temperature liquid-solvent direct air capture is based on a liquid solution of a strong base, which is contacted with air and then processed to yield calcium carbonate ($CaCO_3$). The application of high-temperature (900°C) heat in a calciner liberates the CO_2 from the $CaCO_3$ for compression and storage.

Low-temperature solid-sorbent direct air capture is based on solid amine sorbents that remove CO_2 from air upon contact. Low-temperature (80–100°C) heat is applied to release the CO_2 for compression and storage. Both processes re-use the capture material (liquid solvent or solid sorbent) through many cycles to improve unit economics.

The energy requirements of the two processes are similar, with the majority of energy consumed in the form of heat (approximately 80%) and the remainder in electricity. However, the high temperature required by high-temperature liquid-solvent direct air capture requires dedicated heat production, while waste heat could be used (up to some capacity) for low-temperature solid-sorbent direct air capture. In either case, low-net-carbon heat and electricity input is needed to minimize the costs of net CO_2 removal. To reflect this, we examined five direct air capture scenarios:

- High-temperature liquid-solvent direct air capture using natural gas, with associated flue gas capture (“LSNG”)
- Low-temperature solid-sorbent direct air capture using waste heat (“SSWH”)
- Low-temperature solid-sorbent direct air capture using geothermal heat (“SSGT”)
- Low-temperature solid-sorbent direct air capture using geothermal heat and an additional heat pump to raise its temperature (“SSHP”)
- Low-temperature solid-sorbent direct air capture using solar PV and battery storage (“SSPV”)

Because the overall potential for the low-temperature solid-sorbent waste heat case is quite small, it is not considered in the following learning curve analysis. Also, because the capital costs associated with the low-temperature solid-sorbent geothermal + heat pump case are almost the same as for the SSGT case, it is not considered separately in the following learning curve analysis (see Chapter 5 for further details).

A major difference between the liquid-solvent and solid-sorbent direct air capture technologies is their inherent scaling capability. The calciner system at the heart of the high-temperature liquid-solvent- natural gas case is impractical to scale below a certain minimum capacity, which Carbon Engineering estimates is 100 kilotons of CO_2 per year [188]. This implies that individual high-temperature liquid-solvent natural gas plants will be very large. The capacity for the first commercial plant scheduled for commission in 2023 is 1 million tons of CO_2 per year [242].

By contrast, the solid-sorbent technology developed by Climeworks is inherently modular with a unit capacity of 50 tons of CO_2 per year and can be deployed at the individual-module level [243]. Global Thermostat states its technology can be deployed in containerized form at a minimum scale of 1,000 tons of CO_2 per year [244]. This suggests that these plants could be built at much smaller scales (which is indeed the case for the approximately 10 facilities currently operating) and would be scaled to larger capacities by simply adding modules. This ability to deploy at small scales suggests that the solid-sorbent direct air capture technology will be able to iterate more rapidly than liquid-solvent direct air capture technology, which is generally a desirable feature for technology learning (see below for further discussion).

Some fraction of CO_2 removal targets may be met with biomass pyrolysis producing liquid fuels and/or gasification. Biomass gasification is a mature technology, and while biomass gasification plus carbon capture has not yet been commercially deployed, it consists of commercially available units than can in theory be readily integrated. Unlike biomass gasification options, pyrolysis is relatively new technology that will benefit from learning. Global deployment of biomass pyrolysis units that are operational or under construction is quite small, with a total processing capacity under 1,000 metric tons per day. Techno-economic analysis suggests that the optimal capacity for individual plants is 2,000 tons per day, implying that a single plant of this scale would more than double global capacity (see Chapter 4).

Learning Curves

One of the most fundamental observations about emerging hardware technology is that it tends to get less expensive over time. Many researchers have proposed reasons for this and tried to mathematically model the process. The first reported example was over eighty years ago by T. P. Wright for aircraft production, and dozens of other technologies have been similarly studied since then [245]–[248].

These studies have found that many hardware technologies follow a learning curve (sometimes called an experience curve) pattern of cost reduction, in which the cost of producing the next unit of a given technology falls by a fixed percentage each time the total (cumulative) produced stock

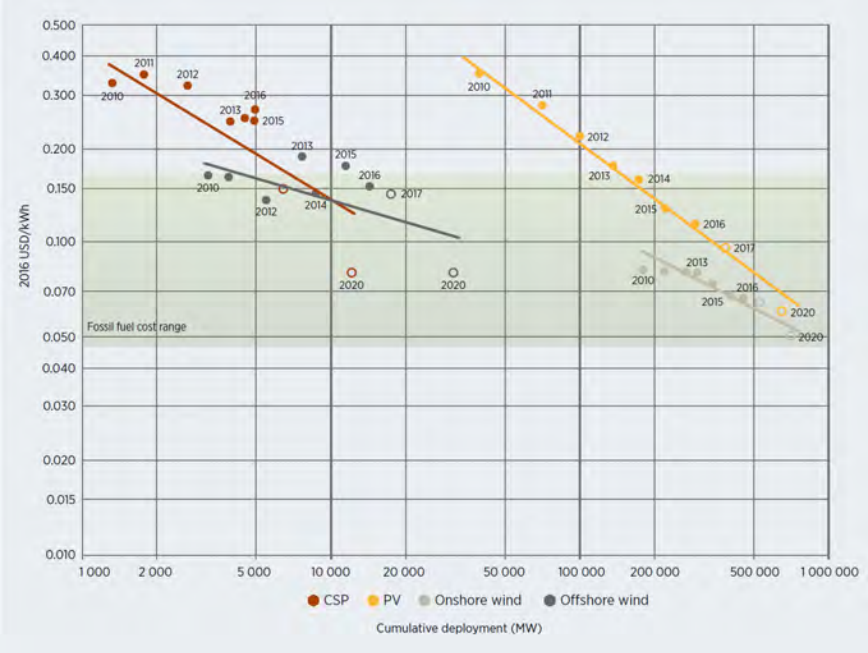


Figure 67. An example of learning curves for solar and wind electricity generation.
(CSP: concentrating solar power; PV: photovoltaics.) These technologies follow one-factor learning curves with learning rates between 10% and 30% [IRENA, 2018]

of the technology doubles (see Figure 67). It is important to note that "cost of production" refers to the capital cost and does not necessarily imply that the operational cost changes.

The effects behind this learning pattern are extremely varied, and can include simple economies of scale, streamlined and standardized supply chains (including incorporating commodity components rather than specialty ones, expanding the manufacturing base, and harmonizing/standardizing component sizes, interconnections, etc.), and (most importantly) true learning by technology designers, manufacturers, installers, and operators about fundamentally lower-cost approaches to the design, production, installation, and operation of the technology [241]. Conceptually, the central insight of learning curve analysis is that as society gains experience with a technology, it learns new or improved methods to produce and use it more cheaply, with the cumulative amount of production serving as a proxy for the amount of experience that has been accumulated. This overall effect is referred to as learning-by-doing, and technologies are said to move down the learning curve as a result.

Simple learning curves (also known as one-factor) are characterized by only two parameters: an initial technology (capital) cost at the starting time of first deployment, and a learning rate factor that represents the fractional (capital) cost reduction with each doubling. Many more complex models have been proposed, but the simple learning curve usually agrees best with empirical cost data [246]. The one-factor learning curve is expressed mathematically as:

Equation 5. *One-Factor Learning Curve.*

$$C(x) = C_0(1 - LR)^{\log_2(x/x_0)}$$

Where C(x) is the cost of producing the next unit after a cumulative total production of x, C_0 is the cost of first deployment, x_0 is the size of first deployment, and LR is the learning rate (often expressed as a percentage). The concept of "x amount of total production" is usually taken to mean a capacity-normalized amount, for example the total generating capacity (in Watts) of PV panels produced or the total storage capacity (in Watt-hours) of batteries, rather than a simple count of individual unit numbers. It is worth noting that an alternative way to quantify the amount of a technology that has been deployed would be to measure the cumulative operational amount, such as the amount of electricity generated (in kilowatt hours). This approach is successful in some cases but is less common.

Learning effects are most easily observed for technologies that are relatively immature, in the sense that there has been only a limited amount of commercial deployment. Very mature technologies, with long histories of manufacture and deployment, tend to display little discernable learning. This is primarily due to the large size of the cumulative installed base, meaning that observing several doublings of the cumulative capacity is unlikely, or would take an enormous amount of additional production.

The Role of Research and Development

One immediate implication of learning curve analysis is that true cost reductions require actual manufacture and deployment of a technology, not just research and development. While certain forms of research and development, if successful, can reduce the initial cost of the first deployment of a technology, it is difficult for these forms to deliver sustained cost reductions without being directly coupled to real-world deployment experience.

An important caveat to this point is the distinction between curve-following and curve-shifting research and development [249]. The former comprises research and development that attempts to improve technology cost or performance within the primary technology base, by incremental improvements to design, manufacturing, installation, and/or operation. The intent of this research and development is to anticipate learning that would have occurred during production and incorporate it into the technology before scaling the production, or in parallel with scaled-up production. While some of this form of research and development is supported by government research efforts, it is also very common among private companies that are seeking short-term cost reductions in the context of commercial production. In terms of the one-factor learning curve model, successful curve-following research and development effectively acts as virtual production, moving the cost down the learning curve.

By contrast, curve-shifting research and development attempts to find a new technology base, in order to fundamentally lower the long-term cost of production. For example, while manufacturing improvements to silicon solar photovoltaic would be considered curve-following research and development, research on perovskite materials for solar photovoltaic would be considered curve-shifting. This latter form of research and development is also referred to as disruptive or breakthrough. If successful, it can essentially define a new learning curve that has the potential to reach (significantly) lower costs in the long term.

It is important to note that the tradeoff between curve-following and curve-shifting research and development is not obvious. Investment in the former does not have the potential for disruptive improvements in the technology cost and performance but is much more likely to yield successful incremental benefits. Investment in the latter is a far higher risk, since most attempts at truly disruptive technology development are likely to fail. Calibrating the optimal balance between these research and development approaches requires a techno-economic evaluation of the likely long-term cost reduction potential of the existing technology base (on the existing learning curve), an evaluation of the performance and cost that will be needed to achieve the overall societal goal of the use of the technology, and an estimation of the value of the embedded learning from the existing cumulative production of the current technology base.

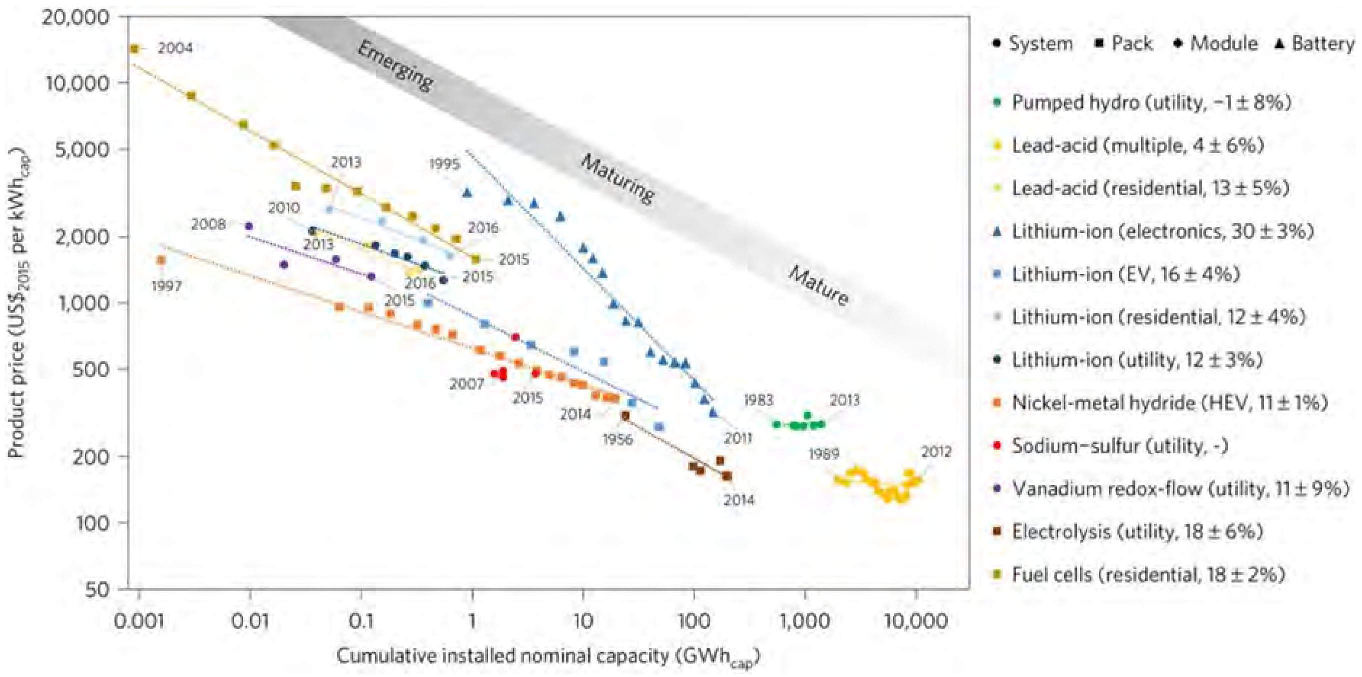


Figure 69. *An example of learning curves for electrical energy storage technology. Most of these technologies (with some exceptions) follow one-factor (simple) learning curves with learning rates between 0% and 30%. [Schmidt, 2017]*

Whatever tradeoff is ultimately favorable in a given technology context; deployment accompanied by an associated research program appears to lead to the best cost-reduction outcomes. This is relevant because governments intending to support the development of a technology have two basic options (which are not mutually exclusive): funding research and development (known as technology push), and funding or stimulating deployment (known as market pull). In California's case, an additional consideration is the role of federal policy. See below for an expanded discussion on this point.

Learning Over Time

A key aspect of the learning curve model is that it depends on total cumulative production of a technology, not on time. In other words, it is not possible to directly infer a date by which the cost of a technology will fall by a certain amount from the learning rate. To do this, one must assume or pose a hypothesis about the rate at which the technology will be manufactured and installed, or equivalently a total amount (i.e., capacity) that will be manufactured at various benchmark dates. This installation rate can then be combined with the learning curve to extrapolate cost reductions over time.

An obvious corollary of this fact is that technology learning and cost reduction can occur quickly or slowly, depending on the rate at which the technology is manufactured and installed. By accelerating investment in production, learning occurs more quickly, and costs drop faster. By contrast, if production slows and the total cumulative produced base of the technology takes a long time to reach a doubling, cost reductions will be correspondingly slower.

A closely related corollary of the learning curve is that early cost reductions are the easiest to achieve, because the net production required to double the total cumulative production is small. The fractional reduction in cost (or equivalently, the increase in learning) accomplished by these early doublings can therefore be bought relatively cheaply by investing in a small amount of production. Achieving the same fractional cost reduction later in a technology's maturation would require a much larger investment in additional production, because of the correspondingly larger amount of production required to double the cumulative total.

Exceptions to Learning Curve Behavior

While most technologies that have been studied with a learning curve framework show clear learning effects, there are some exceptions. The most notable is nuclear power, which appears to show negative learning, meaning that the cost of nuclear plants (normalized by generation capacity) increases with the cumulative deployed amount of nuclear power (see Figure 69) [250]. Several reasons have been proposed for this, including regulatory requirement changes. However, an important factor appears to be the fact that nuclear plants are site-built (i.e. not primarily manufactured) and somewhat unstandardized. This means that each new plant requires some unique design elements and engineering analysis, and the experience of previous plants is of limited use. It also means that it is not possible to gain all the benefits from working in a controlled manufacturing environment, in which all aspects of production can be monitored and optimized. While individual components can be optimized in a manufacturing environment, the site-specific installation can reduce or negate these cost-saving benefits.

This example raises the obvious question of whether direct air capture and pyrolysis are likely to be an exception to learning curve behavior and may even follow nuclear power in displaying negative learning. The core lesson from the nuclear example is that standardized technologies, particularly ones that are factory-built (manufactured) under fully controlled conditions that can rapidly implement design improvements from learning, are best-suited to maximize the cost-reduction advantages from learning. Standardization also leads to the greatest benefits from harmonized, commoditized supply chains. Solar photovoltaic illustrates this feature of learning, since module sizes and powers were relatively standardized early in the development of the technology, and solar photovoltaic installations have relatively few site-specific elements that required additional, non-standard engineering or design that would inflate costs and erase the impacts of learning.

In the case of direct air capture, solid-sorbent systems fit the standardized and modular characteristics well. These units can be mass-produced, under controlled factory conditions, and can rapidly implement design or manufacturing improvements that are identified during deployment scale-up. In addition, as noted above, they can operate at small as well as large scales, offering a path to early, rapid deployment that enables fast iteration and learning. By contrast, liquid-solvent direct air capture is much closer to the profile of conventional nuclear power plants, because it is site-built, monolithic, and large-scale. This suggests these direct air capture systems would likely be less able to incorporate rapid design or manufacturing improvements, even if the total capacity produced increases rapidly.

The implication of these factors is that solid-sorbent direct air capture is likely to have a faster learning rate (a larger LR in Equation 5 above) than liquid-solvent direct air capture and

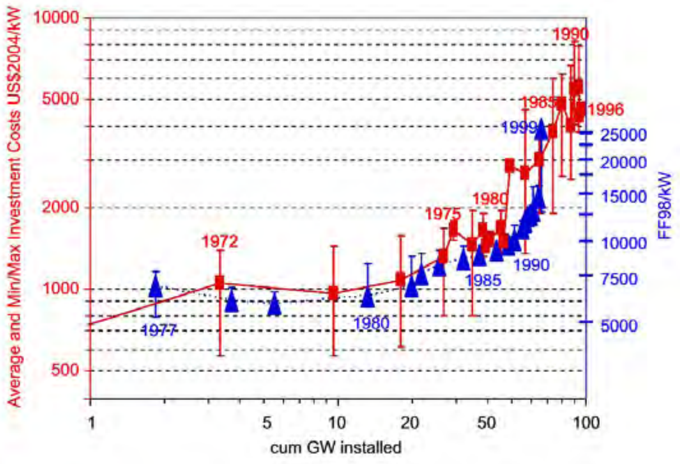


Figure 69. *Construction costs of nuclear reactors in France (blue; expressed in 1998 French francs per kW) and the US (red; expressed in 2004 US dollars per kW). Nuclear power is one of the few technologies that display "negative learning", by which average costs rise as the total produced amount of the technology grows. [Grubler, 2010]*

is likely to fall in cost more quickly for the same cumulative production amount. The higher learning rate essentially means that more learning, and thus more cost reduction, can be bought per dollar of public investment.

The case of biomass pyrolysis is more difficult to analyze in this context. While some elements of the system may need to be site-built, there will likely be substantial amounts of the system that are standardized. This suggests the biomass pyrolysis technology under consideration is likely to have a moderate learning rate.

Considerations for California to Support Direct Air Capture and Pyrolysis Technology Development

Efforts to enhance learning rates of negative emissions technologies should consider the following parameters.

1. The form of support could emphasize either deployment (market pull) or research, development, and demonstration (technology push). The former would generally be in the form of deployment incentives, procurement requirements or related policies that encourage the installation and/or operation of direct air capture or pyrolysis facilities, while the latter would generally be in the form of research grants to support the development of experimental direct air capture or pyrolysis technologies. In this context, it is worth noting that the federal government (primarily the United States Department of Energy) will potentially fund substantial research, development, and demonstration in direct air capture technology development beginning in 2020 . Some of these funds may be awarded to California research institutions, and the results from all the research will generally be made publicly available. There is currently no clear indication that the United States Department of Energy intends to fund substantial new research on biomass pyrolysis.
2. Deployment support can generally be based on subsidizing either capital costs or operating costs. The United States Solar Investment Tax Credit is an example of the former (lowering the effective cost of installation) whereas feed-in tariffs (such as in the United Kingdom) are an example of the latter, lowering the effective cost/increasing the effective profitability of operation. Currently, the only federal support for deployment of direct air capture facilities is the Section 45Q tax credit, which provides incentives on a per-ton-removed basis, assuming the direct air capture plant operator has a sufficient tax appetite. No current federal funding is available for deployment support focused on the capital cost of direct air capture facilities.

Table 38. *Reported direct air capture deployments globally, by year and capacity*

Company	Location	Technology	Year	Capacity (tons CO_2/y)
Global Thermostat	Menlo Park, CA, USA	LTSS	2010	?
Global Thermostat	Menlo Park, CA, USA	LTSS	2013	?
Climeworks	Dresden, Germany	LTSS	2014	?
Carbon Engineering	Squamish, BC, Canada	HTLS	2015	365
Climeworks	Hinwil, Switzerland	LTSS	2017	900
Climeworks	Hellisheidi, Iceland	LTSS	2017	50
Oy Hydrocell	VTT Jyvaskyla, Finland	LTSS	2017	1.4
Climeworks	Troia, Apulia, Italy	LTSS	2018	150
Global Thermostat	Huntsville, AL, USA	LTSS	2018	4000
TOTAL				5466.4

In the case of direct air capture, it appears that there are near-term, small-to-medium-scale opportunities both inside and outside California to (a) claim credits under the Low Carbon Fuel Standard and (b) sell removed CO_2 for profitable uses. These early market conditions, and the Section 45Q Federal tax credit, imply that operational costs will be partly defrayed for early direct air capture entrants. By contrast, raising capital from private markets to build direct air capture plants seems far less certain. Potentially viewing direct air capture as an unproven technology, lenders will be unlikely to offer low rates for capital. Ways to address this could include direct (cost-shared) grants for direct air capture capital costs, or some form of loan guarantee that would reduce the cost of borrowing on private markets. Similar considerations apply to biomass pyrolysis facilities.

Below, we consider the case of deployment support in the form of public subsidies for the capital cost of direct air capture and pyrolysis facilities.

Air Capture Learning

To assess the potential for cost reduction in direct air capture and pyrolysis technology, we developed a simple model of deployment with associated learning. For the case of direct air capture, the model begins with a projected deployment scenario for direct air capture in terms of cumulative CO_2 removal capacity installed, expressed in tons of CO_2 per year. The scenario does not attempt to model deployment over the next five years, but instead assumes that 1.5 million tons of CO_2 per year of direct air capture will be deployed by 2025 outside of California, and 0.1 million tons of CO_2 per year in California, in close agreement with a scenario developed by Rhodium Group [251]. For reference, the reported total capacity of direct air capture facilities worldwide in 2020 is approximately 5.5 kilotons of CO_2 per year (several pilot facilities whose capacity is unknown are considered too small to include in this analysis, see Table 38). However, Carbon Engineering announced in May 2019 that it was beginning engineering development of a 0.5 million tons of CO_2 per year direct air capture plant, which is expected to be operational in 2023 [252]; the plant's planned capacity was later expanded to 1 million tons of CO_2 per year [242]. The company also announced that it plans to expand this to multiple megaton-scale plants in the future. These announcements underpin the assumption of million tons of CO_2 per year-scale direct air capture deployment by 2025.

Starting from the initial direct air capture deployment in 2025, the cumulative deployed capacity in the model grows exponentially (see Figure 70). We examine two versions of the model, one in which the total installed capacity of direct air capture in California by 2045 reaches 43 million tons of CO_2 per year (low direct air capture)and another in which it reaches 85 million tons of CO_2 per year (high direct air capture). For both versions, we assume that direct air capture will also be installed outside of California during this time period. Our conservative estimate is that this amount will match the California deployment in the smaller (low direct air capture) scenario. (These amounts exceed what we anticipate California will require but are inclusive of possible scenarios where only minimal natural solutions or biomass are available. This estimate is approximately 4 times smaller than the estimate developed by the Rhodium Group [251].) Because the companies designing and building direct air capture are currently operating in multiple jurisdictions, we assume that the learnings from direct air capture installations outside of California will contribute to cost reductions for direct air capture installed in California.

We next calculated the impacts of a one-factor learning curve on the capital cost of direct air capture under the two scenarios. This is essentially asking the question: "If direct air capture technology is built and installed according to this future deployment scenario, how rapidly will the cost to build the next direct air capture plant fall?" It is important to note that we apply this learning to the capital cost only, reflecting patterns observed with other analogous technologies. We do

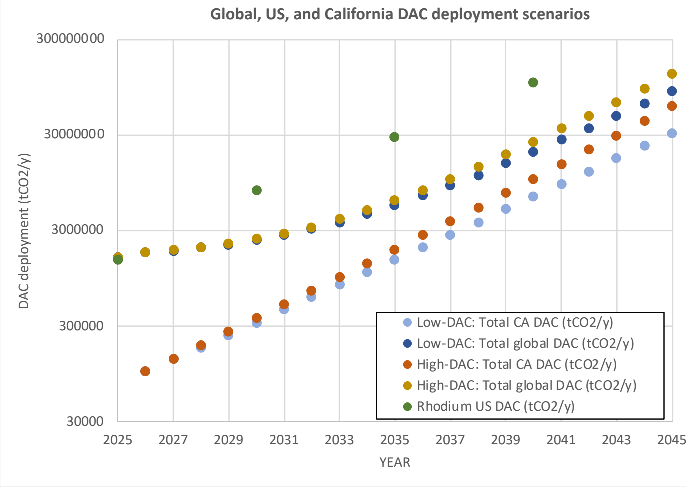
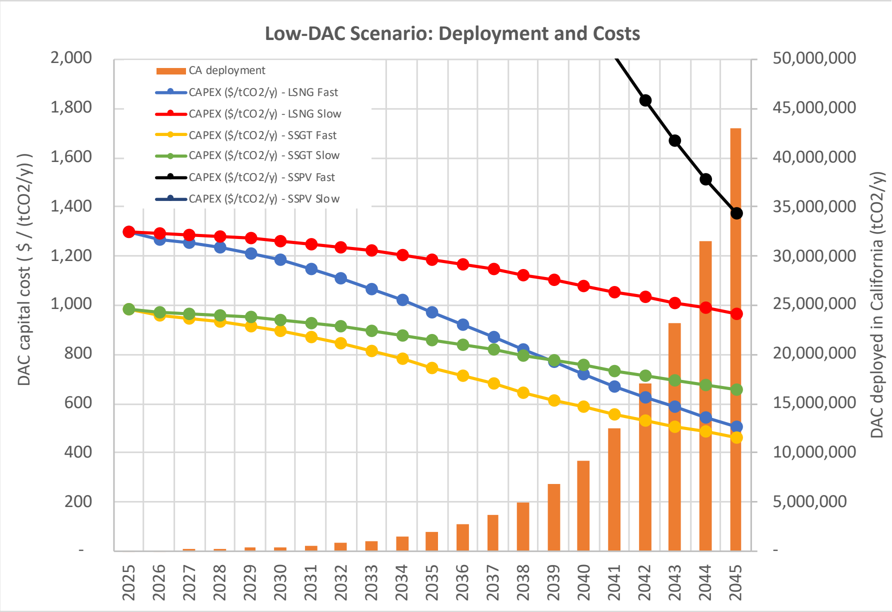


Figure 70. Deployment scenario for direct air capture developed for this analysis. *Light blue dots: modeled direct air capture deployment in California, including facilities physically in California and facilities supported by California policy (low direct air capture scenario);* ***Dark blue dots:*** *modeled global direct air capture deployment (low direct air capture scenario);* ***Orange dots:*** *modeled direct air capture deployment in California (high direct air capture scenario); Yellow dots: modeled global direct air capture deployment (high direct air capture scenario).* ***Green dots:*** *deployment scenario (mid-range) developed by Rhodium Group [Larsen, 2019].*

not assume any learning (i.e., cost decrease) in the operating costs, such as improvements in the energy efficiency of direct air capture. This means that our learning estimates are relatively conservative, and that operating costs will grow in importance over time compared with capital costs, in our model.

The learning calculation begins by specifying the capital cost at the beginning of the scenario time period (2025) As described in the direct air capture chapter, for the liquid-solvent technology with natural gas scenario, we use an initial capital cost of $1,299 per ton of CO_2 per year capacity. For the solid-sorbent technology with geothermal heat scenario (SSGT), we use an initial capital cost of $715 per ton of CO_2 per year, with an additional capital cost of $276 per ton of CO_2 per year for drilling the geothermal well. We separate well-drilling capital cost because we assume there will not be any significant learning effects for geothermal well drilling based on wells drilled for use with direct air capture under these scenarios; this is a conservative assumption. For the solid-sorbent technology with solar photovoltaic and batteries scenario, we use an initial capital cost of $4,982 per ton of CO_2 per year capacity.

The remaining issue is to select an appropriate estimated learning rate (LR in Equation 5 above). Many hardware technologies display learning rates in the range of 5% to 20% [247], [248]. As discussed above, the factors that lead to fast and slow learning concluded that liquid-solvent technology was likely to learn at a slower rate compared with solid-sorbent technology. Therefore, we modeled sub-scenarios of fast and slow learning for the liquid-solvent case with a learning rate of 15% and 5%, respectively (reflecting uncertainty in the actual learning rate). We also modeled sub-scenarios of fast and slow learning for the solid-sorbent case but with a more aggressive learning rate of 20% and 10%, respectively. Following this, we calculated the capital cost reduction factor associated with the deployment at each year in the model, for both fast and slow learning (see Figure 71).



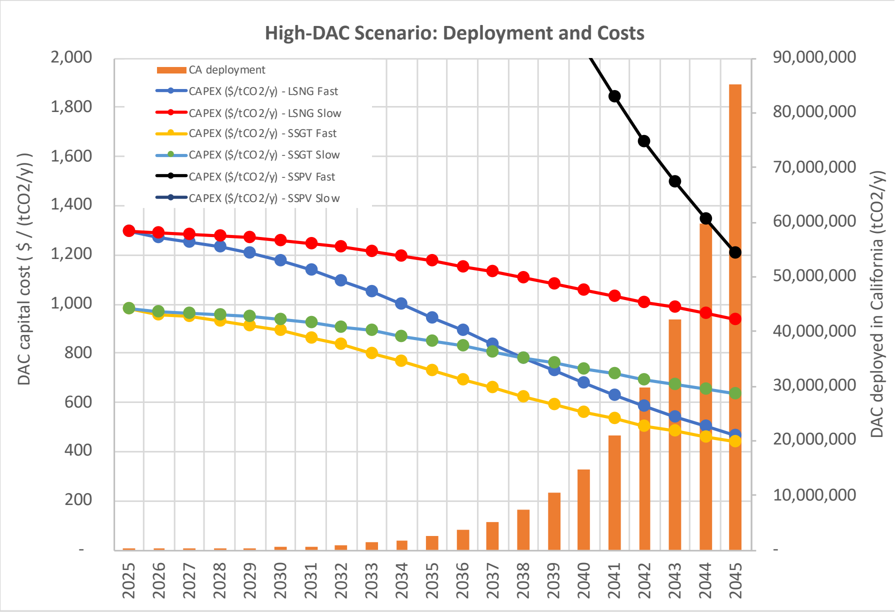


Figure 71. *Capital cost reduction of several direct air capture configurations under the "low direct air capture" scenario* **(Top)** *and the "high direct air capture" scenario* **(Bottom)***. LSNG = liquid-solvent direct air capture with natural gas energy; SSGT = solid-sorbent direct air capture with geothermal energy; SSPV = solid-sorbent direct air capture with solar photovoltaic energy and battery storage. Also shown is the total deployed direct air capture in California (or within the California program) over time.*

At this point it is important to note that our learning models do not actually consider time, but only the number of units deployed. This allows us to make an important simplification. We can consider the learning purely in terms of how many units have been constructed worldwide, in association with the construction of the units in California. When thought of this way, the only important factor is how many units are built worldwide, and our two scenarios (high direct air capture and low direct air capture) can be merged into one plot. Figure 72 displays the learning curves for the two technology classes in this format. The geothermal case is relatively simple: it only considers units built in California, although there may be some development elsewhere, we have not considered it. Thus, the chart stops at 11 million tons for geothermal/solid sorbent technology. For natural gas a choice has to be made for how many units are developed outside of California – we chose the low direct air capture case (Figure 71). Thus, when California has constructed 12 million tons of natural-gas-powered direct air capture, we assume that the world has constructed another 36 million tons. Since this case is not limited by the amount of geothermal available in California, the costs for natural gas systems can be calculated for much larger amounts of deployment than for geothermal-powered systems. As described in the air capture chapter, the growth of the natural gas systems is assumed to begin in 2025 with 1.5 million tons of capacity, and geothermal with 50 thousand tons of capacity.

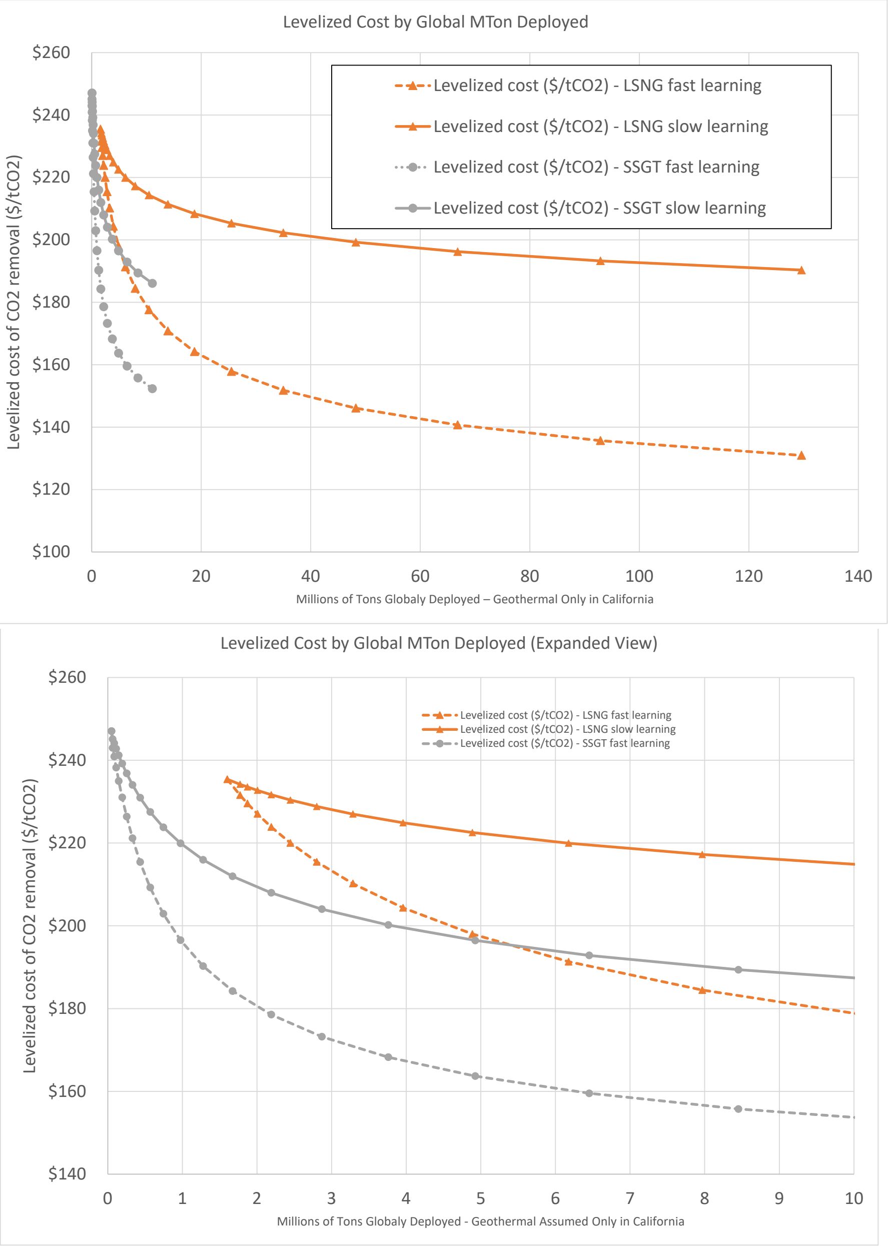


Figure 72. *(A) Levelized cost of direct air capture for natural gas* ***(orange)*** *and geothermal* ***(grey)*** *powered systems. Solid* ***(upper)*** *lines represent slow learning, and dashed* ***(lower)*** *lines represent fast learning. For geothermal powered systems only development in California is considered, limited to 11 million tons of capacity represented by the untapped heat in the Salton Sea. Other development, or utilization of existing geothermal power as described in the direct air capture chapter, would result in extension of this plot to higher numbers of tons deployed along a similar cost curve. Natural gas deployment is assumed to occur worldwide as shown in Figure 70* ***(top)*** *Low direct air capture scenario. (B) the same data expanded to show the importance of early learning.*

We derived the levelized cost of CO_2 removal by combining the capital cost in an annualized form with the annual operating costs, normalized to one ton of CO_2 removed. This levelized cost falls over time because the capital cost falls; as noted earlier, we assume that the operating costs stay fixed throughout the 2025–2045 period (a conservative assumption). Additionally, the capital cost to drill geothermal wells in the SSGT case stays fixed, because we assume no learning will occur for this relatively mature technology as a result of the relatively small total new capacity of wells that would be drilled.

To calculate the range of levelized costs for the liquid-solvent natural-gas (LSNG) and low-temperature solid-sorbent geothermal heat (SSGT) cases, we converted the capital cost to an annualized capital cost using a capital recovery factor as described in the direct air capture chapter. For the LSNG case, this is 12.5%, the value used in the peer-reviewed literature. For the SSGT case, this is 18%, with the higher number reflecting the estimated shorter lifetime of these plants and the corresponding requirement for faster capital recovery. Next, we added the annualized capital cost (per ton of CO_2 removed) to the operating cost (per ton of CO_2 removed) to arrive at the levelized cost. In 2025, this is \$235 per ton of CO_2 for the liquid-solvent natural-gas case and \$247 per ton of CO_2 for the low-temperature solid-sorbent geothermal heat case (since no learning is assumed to have occurred in the first year, these are starting values, not ranges).

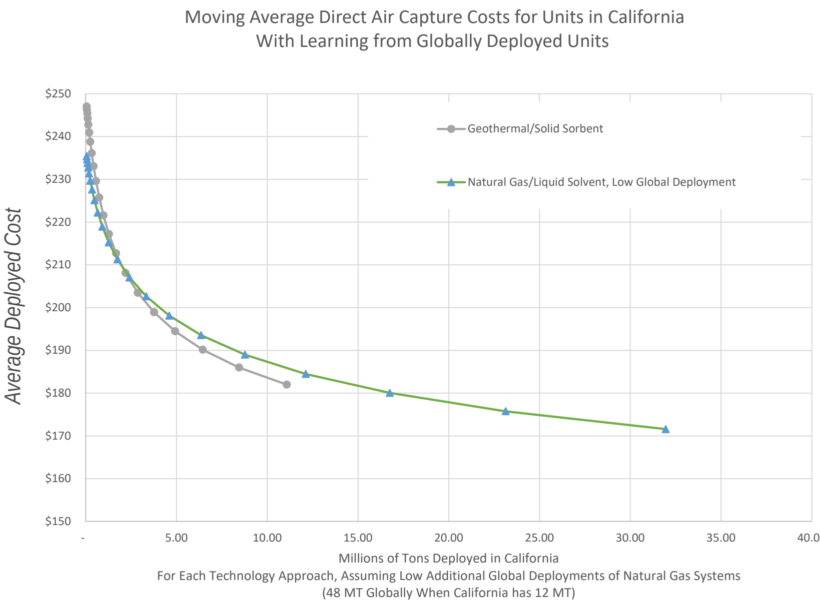


Figure 73. *Levelized average cost per ton of CO_2 of direct air capture, following the deployment represented in Figure 71 and annual costs of new facilities shown in Figure 72.*

These costs are for the creation of new capacity in each year. For the goal of achieving the total used in our system evaluation (e.g. for the gasification priority scenario, 11 million tons of geothermal powered direct air capture and 4.7 million tons of natural gas powered direct air capture) we need to know the average cost as the plants are constructed. For that we assumed that at each point shown in Figure 72 capacity is constructed at the average cost of the two learning curves (fast and slow learning). This gives us Figure 73 which shows the average cost of the fleet of facilities existing in California in 2045, for any amount of total direct air capture constructed in the State, as long as worldwide construction mirrors California's pace according to the low direct air capture scenario above. Thus, this is a conservative estimate of the amount of learning that California could take advantage of. If more development occurred outside of California, particularly for geothermal-powered systems, the costs would be lower.

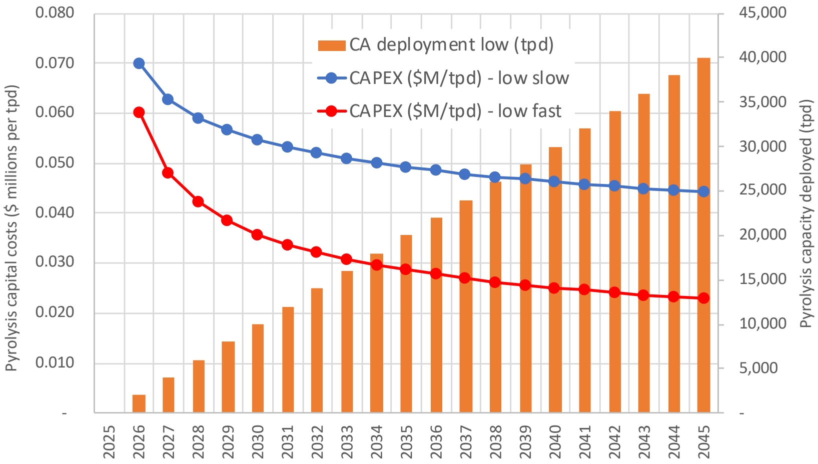


Figure 74. *Biomass pyrolysis capacity deployment and capital cost reductions from learning; low deployment scenario. tpd = tons per day.*

Pyrolysis Learning

For the case of pyrolysis, the model begins with projections of deployment in California and/or within the California program. In contrast to direct air capture, we cannot estimate interest in global deployment of the technology; therefore, we examined learning only within the California-specific deployment projections. We examined a low scenario of the deployment of one 2,000-tons per day facility every year, leading to 20 such facilities by 2045, Figure 74; and a high scenario of five 2,000-tons per day facilities built every two years (approximated as 2.5 per year), leading to 50 such facilities by 2045, Figure 75. We examined two learning scenarios—one called "fast" with a learning rate of 20%, and one called "slow" with a learning rate of 10%. We estimated the starting capital cost at $160 million for a 2,000-tons per day plant, or $0.08 million ($80,000) per ton per day capacity. Finally, we estimated the global deployed capacity of biomass pyrolysis in 2025 to be 820 tons per day, reflecting currently operating plants and those under construction.

Using these parameters, we estimated the changes to capital cost for facility construction that result from learning. In 2035, capital cost has fallen between 39% (the low slow scenario) and 74% (the high fast scenario). In 2045, capital cost has fallen between 45% (low slow) and 79% (high fast).

We considered the extent to which learning would be important for the capital cost development of biomass treatment methods, particularly our two leading candidates, pyrolysis and gasification. We believe that gasification is a fairly mature technology and would not change price much do to California applications, However, pyrolysis is in about the same learning stage as direct air capture with storage and should benefit.

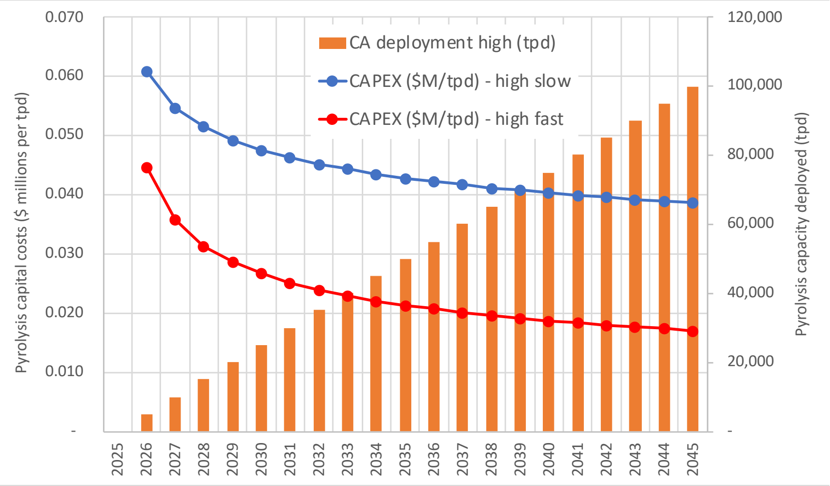


Figure 75. *Biomass pyrolysis capacity deployment and capital cost reductions from learning; high deployment scenario. tpd = tons per day.*

We applied learning curve analysis to the biomass fast pyrolysis to liquid fuels scenario in order to understand how learning could affect the total system capital cost from the pyrolysis and bio-oil upgrading system from 2025 to 2045. We evaluated the high deployment scenario assuming an incremental deployment of 5,000 ton per day capacity every year as shown in Figure 75. This assumes total facilities to only be in California (any other worldwide application would result in further decreases in cost). As with air capture, slow and fast learning rates of 10% and 20% cover the learning rate uncertainty. As with direct air capture with storage, we only apply learning on the pyrolysis capital cost, and keep the capital cost for any auxiliary units required to capture CO_2 and upgrade to a finished product as fixed over time. Figure 76 shows the total system capital cost for a 2,000 ton per day capacity facility, converting biomass into liquid fuels; as shown, we can expect total system capital cost of the pyrolysis and bio-oil upgrading process to decrease by 20% as the total deployed pyrolysis capacity increases from 5,000 to 100,000 tons per day, which can significantly decrease the negative emission cost for this pyrolysis to fuel system.

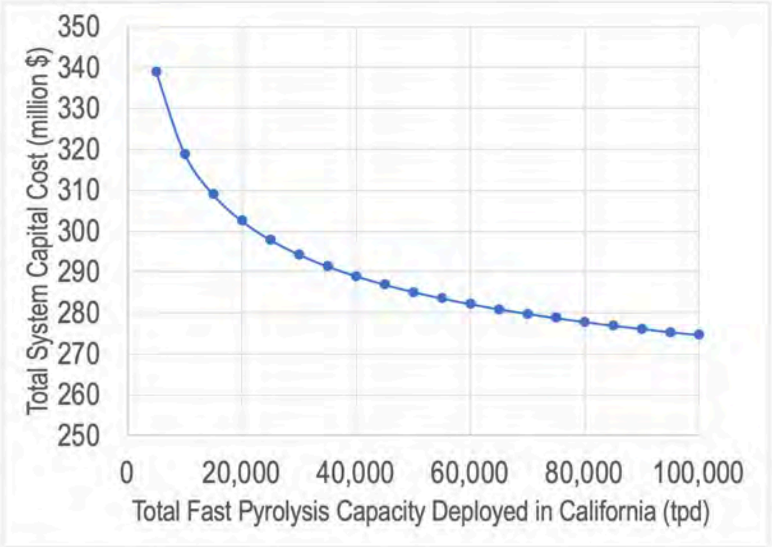


Figure 76. Moving average fast pyrolysis-to-fuel system capital cost curve for deployment in California for a 2,000 ton per day facility. *The values here are derived by assuming average learning of the high deployment scenario shown in Figure 75.*

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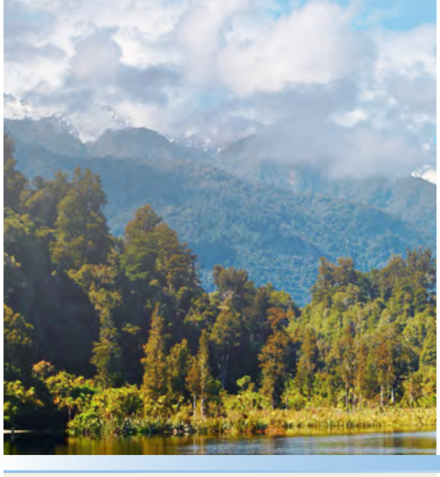
CHAPTER 9

Total System Cost



SUMMARY

In our previous chapters, we presented the three prongs of our negative emissions solution—natural solutions, biomass conversion, and direct air capture—and considered the costs, capacity, and logistics of permanent geologic storage and transportation, as well as the effects of learning on the cost of key technologies.

In this chapter, we present three scenarios that bring together findings from the above chapters to achieve 125 million tons of negative CO_2 emissions per year. The three scenarios represent the lowest-cost pathways for producing each of three energy coproducts. Our first scenario, Gasification Priority, prioritizes production of hydrogen from biomass; this scenario has the highest negative emissions potential and lowest cost of the three. The Pyrolysis Priority Scenario prioritizes production of liquid fuels from biomass; this coproduct can help displace fossil fuel use from hard to decarbonize sectors like air transportation and heavy industry. The Combustion Priority Scenario prioritizes production of electricity; this has the lowest capital cost and uses mature technology. In practice, the scenarios can be mixed to provide a portfolio of coproducts, yielding negative emissions costs in between the results that we present.

We also investigate the sensitivity of the total cost of the system and the cost of negative emissions to the most important uncertainties in our scenarios: the total availability of biomass, the cost of direct air capture, and the selling price of energy coproducts.

Key Findings

A summary of total system costs is shown below. The Gasification system cost of $8 Billion/yr amounts to 6% of current state government spending and about 0.1% of California's current gross domestic product in 2045. We find the costs of meeting negative emissions goals to be quite moderate, suggesting that the State can achieve carbon neutrality by 2045.

Scope of Chapter

Estimating the total cost of removing 125 million tons of CO_2 per year from the atmosphere. This chapter brings together findings from the previous eight chapters to construct complete negative emissions scenarios. We show the costs of negative emissions pathways after adding transport and storage and add up sets of pathways to calculate the total system cost. We also assess the effects of the following parameters on total cost:

- Choice of biomass conversion technology (gasification, pyrolysis, combustion)
- Sale prices of coproducts (hydrogen, liquid fuel, electricity)
- Total availability of biomass
- Cost of direct air capture

Scenario	**System Total Cost ($Billion/yr)**	**System Average Cost ($/ton CO_2)**
Gasification Priority Scenario	8.1	65
Pyrolysis Priority Scenario	13.9	111
Combustion Priority Scenario	10.1	81

Introduction

In this chapter, we present three scenarios that bring together all of the cost components from each of the three pillars with transport and geologic storage costs to achieve 125 million tons of negative CO_2 emissions per year. Each scenario prioritizes production of a different energy coproduct. We present cost curves that show the cost of each scenario component, the negative emissions available via that component, and the additional benefit that could be realized by producing the energy coproducts from biomass instead of fossil resources.

Gasification Priority Scenario

The first set of pathways that we present is called the Gasification Priority Scenario. This set includes all the natural solutions described in Chapters 2, amounting to 25 million tons per year. For the biomass conversion pathways, we selected the lowest-cost option per ton of CO_2, which also happens to be the option with the highest negative emissions potential: gasification to hydrogen. With this technology, virtually all of the carbon in the biomass is captured and stored underground, while carbon-neutral hydrogen fuel is produced as a coproduct. To calculate avoided emissions, we assume that this hydrogen displaces hydrogen produced by steam methane reforming. In this case, the gasification pathway also yields substantial mitigation benefits, making it the best choice both in terms of negative emissions and combined negative and avoided emissions. Gasification applies to all four of the dry biomass categories, and a gasification plant can process a combination of these types. Gasification thus offers synergies in terms of transport and logistics, and this leads to lower transportation costs for gasification than most other technologies examined. Although gasification plants are large, there is some flexibility in siting them because the biomass feedstocks can be transported by rail at relatively low cost. For the purposes of the calculation, we assume that gasification plants are spread throughout the Central Valley along a CO_2 trunk pipeline, but other configurations can yield similar costs. Gasification plants also emit dramatically lower amounts of criteria pollutants than do conventional biomass energy plants.

For biogas sources, such as landfills and wastewater treatment plants, we select the lowest-cost pathway, which also has the highest carbon removal potential. Raw biogas is purified at the source locations and the resulting CO_2 is captured and trucked to the nearest CO_2 pipeline. Meanwhile, the resulting biomethane is injected into a natural gas pipeline and later burned in a natural gas combined cycle power plant that has been retrofitted with CO_2 capture. These plants produce the only electricity coproducts in the Gasification Priority Scenario. The power plants, we assume, are located close to a CO_2 pipeline.

For direct air capture, we first assume extensive use of geothermal resources because this is a lower-cost and lower-impact approach. We estimate that a geothermal direct air capture plant at the Salton Sea could capture 11 million tons of CO_2 per year. Solvent direct air capture is the highest-cost pathway in this set, and we apply it to fill the gap between the negative emissions provided by other pathways and the total of 125 million tons per year. This amounts to only 5 million net tons CO_2 per year provided by conventional direct air capture in this scenario. Since conventional direct air capture siting is flexible, we assume they build directly on or adjacent to storage sites, so the there is no transport cost for solvent direct air capture. The cost results for the gasification scenario are shown in Table 39 on a negative emissions basis and Table 40 on a combined negative and avoided emissions basis.

Pyrolysis Priority Scenario

Although gasification to hydrogen is an appealing technology in our estimates, other technologies could be more favorable in various future circumstances. Other sets of pathways can also meet negative emissions requirements while producing different coproducts. Pyrolysis is the lowest cost and most productive method to produce liquid fuels from forest biomass and agricultural residues, which in turn can displace fossil fuel emissions in hard-to-mitigate applications like aircraft, heavy industry, and legacy vehicles. Pyrolysis also produces biochar, which can either store carbon in soil or be used as a fuel in industrial processes, like cement kilns.

The pyrolysis scenario is an alternative set of negative emissions pathways that essentially maximizes the production of liquid fuels. Pyrolysis isn't considered applicable to municipal solid waste, so we retain gasification to hydrogen for that source type. However, in this scenario pyrolysis is applied to dry agricultural residues, sawmill residues, and forest management wastes. Pyrolysis plant logistics favor siting the plants near large biomass sources, so for the purposes of the calculation, dozens of pyrolysis plants are sited in forested regions and others around the Central Valley. Some other configurations would yield similar costs. Transport costs are higher in this set both because transport on a negative emissions basis is more costly for pyrolysis and because splitting the biomass sources between gasification plants and pyrolysis plants removes some logistical synergy that we had in the gasification scenario.

The natural solutions, biogas, and geothermal direct air capture pathways are the same as for above. However, because pyrolysis has a lower negative emissions potential per unit biomass than gasification, the overall contribution of the biomass pathways is reduced, and more solvent direct air capture is needed to reach 125 million tons. We use 46 million tons of solvent direct air capture in this scenario. The cost results for the pyrolysis scenario are shown in Table 41 on a negative emissions basis and in Table 42 on an avoided emissions basis.

Combustion Priority Scenario

The final scenario considered prioritizes direct combustion of biomass to produce electricity. This scenario has almost as high a negative emissions potential as gasification and a low capital cost. However, since electricity is already mandated to be carbon neutral by 2045, there is no avoided emissions benefit from producing electricity.

Other technology pathways can produce electricity, and gasification can produce more electricity per unit biomass, but combustion is the lowest cost option because the capital cost is much lower. There are operating biomass combustion plants in California, but current biomass combustion technology has struggled with profitability and local opposition due to criteria pollutant emissions. However, the plants proposed in this scenario differ in several important ways. First, they are much bigger than current biomass combustion plants: at about 250 MW, they are similar in size to typical natural gas baseload plants. Second, they are equipped with post-combustion carbon capture systems, which, together with required pre-treatment, reduce the quantity of criteria pollutants from the plants. The larger size of the plant is necessary to achieve economy of scale for the carbon capture system. Finally, assuming some value for negative emissions not included here, these plants generate more value from the CO_2 capture than from the sale of electricity, so the same concerns about profitability do not apply.

We did not evaluate the cost of making the combustion plants rampable, which is difficult with conventional carbon capture systems, but electricity that can be quickly dispatched may be especially valuable in a future with mostly renewable sources on the electricity grid.

By coincidence, our typical plant sizes for gasification and combustion are exactly the same, at 4,500 dry tons biomass

Table 39. *Total Cost Results for Gasification Priority Scenario ,Negative Emissions Basis*

	Quantity, 2025	Quantity, 2045	Conver-sion Cost, 2025	Conver-sion Cost, 2045	Transport Cost	Storage Cost	Total Avg Cost, 2025	Total Avg Cost, 2045
Pathway	million tons CO_2 neg/yr	million tons CO_2 neg/yr	\$/ton CO_2 neg	\$/ton CO_2 neg	\$/ton CO_2 neg	\$/ton CO_2 neg	\$/ton CO_2 neg	\$/ton CO_2 neg
Gasification of Dry Municipal Solid Waste to Liquid H_2	16.1	17.1	14.4	14.4	8.3	6.0	28.7	28.7
Gasification of Sawmill Residue and Shrub & Chaparral to Liquid H_2	14.5	14.5	28.0	28.0	13.1	6.0	47.1	47.1
Gasification of Forest Management to Liquid H_2	24.9	24.9	44.8	44.8	13.0	6.0	63.8	63.8
Gasification of Low Moisture Agricultural Residue to Liquid H_2	16.1	19.5	50.8	50.8	7.1	6.0	63.9	63.9
Biogas to Electricity with Local Carbon Capture (Retrofit Power Plant)	8.4	7.0	76.9	83.7	6.5	6.0	89.4	96.2
Ethanol Fermentation	0.9	0.9	42.4	42.4	6.9	6.0	55.3	55.3
Natural Solutions	6.3	25.5	11.4	11.4	0.0	0.0	11.4	11.4
Geothermal Direct Air Capture	11.0	11.0	247.0	182.0	5.3	6.0	258.3	193.3
Solvent Direct Air Capture	26.9	4.7	235.0	190.0	2.0	8.8	245.8	200.8
Total Negative Emissions	**125**	**125**				**Total System Cost (\$B/yr)**	**14.1**	**8.1**

per day. The resulting flows of CO_2 are very similar, since the gasification plant captures nearly all of the input carbon and the combustion plant captures 90%. As a result, the transport logistics and costs for combustion and gasification are very similar. Similar to gasification, we found that siting the combustion plants throughout the Central Valley along the CO_2 pipeline, and moving biomass to them via truck and rail, is the lowest-cost option.

The natural solutions, biogas, and geothermal direct air capture pathways are assumed to be the same in this scenario as for the above. The amount of solvent direct air capture needed to reach 125 million tons is slightly higher than for the Gasification Priority Scenario, at 10 million tons per year. The cost results for the Combustion Priority Scenario are shown in Table 43 on a negative emissions basis and in Table 44 on an avoided emissions basis.

Table 40. *Total Cost Results for Gasification Priority Scenario, Negative + Avoided Emissions Basis*

	Quantity, 2025	Quantity, 2045	Conver-sion Cost, 2025	Conver-sion Cost, 2045	Transport Cost	Storage Cost	Total Avg Cost, 2025	Total Avg Cost, 2045
Pathway	million tons CO_2 neg +avoided/yr	million tons CO_2 neg +avoided/yr	\$/ton CO_2 neg+ avoided	\$/ton CO_2 neg+ avoided	\$/ton CO_2 neg+ avoided	\$/ton CO_2 neg+ avoided	\$/ton CO_2 neg+ avoided	\$/ton CO_2 neg+ avoided
Gasification of Dry Municipal Solid Waste to Liquid H_2	28.4	30.2	8.2	8.2	4.7	3.4	16.3	16.3
Gasification of Sawmill Residue and Shrub & Chaparral to Liquid H_2	25.6	25.6	15.9	15.9	7.4	3.4	26.7	26.7
Gasification of Forest Management to Liquid H_2	44.0	44.0	25.4	25.4	7.4	3.4	36.1	36.1
Gasification of Low Moisture Agricultural Residue to Liquid H_2	28.5	34.5	28.8	28.8	4.0	3.4	36.2	36.2
Biogas to Electricity with Local Carbon Capture (Retrofit Power Plant)	15.9	7.0	34.4	83.7	6.5	6.0	47.0	96.2
Ethanol Fermentation	0.9	0.9	42.4	42.4	6.9	6.0	55.3	55.3
Natural Solutions	6.3	25.5	11.4	11.4	0.0	0.0	11.4	11.4
Geothermal Direct Air Capture	11.0	11.0	247.0	182.0	5.3	6.0	258.3	193.3
Solvent Direct Air Capture	26.9	4.7	235.0	190.0	2.0	8.8	245.8	200.8
Total Negative + Avoided Emissions	**187**	**183**				**Total System Cost (\$B/yr)**	**14.1**	**8.1**

Table 41. *Total Cost Results for Pyrolysis Priority Scenario, Negative Emissions Basis*

	Quantity, 2025	Quantity, 2045	Conversion Cost, 2025	Conversion Cost, 2045	Transport Cost	Storage Cost	Total Avg Cost, 2025	Total Avg Cost, 2045
Pathway	million tons CO_2 neg/yr	million tons CO_2 neg/yr	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg
Gasification of Dry Municipal Solid Waste to Liquid H_2	16.1	17.1	14.4	14.4	9.5	3.6	27.4	27.4
Fast Pyrolysis of Sawmill Residue and Shrub & Chaparral to Liquid Fuels	4.3	4.3	56.8	-27.0	27.9	3.6	88.3	4.4
Fast Pyrolysis of Forest Management to Liquid Fuels	7.5	7.5	113.2	28.9	24.5	3.6	141.2	57.0
Fast Pyrolysis of Low Moisture Agricultural Residue to Liquid Fuels	4.9	5.9	194.9	110.7	19.0	3.6	217.4	133.3
Biogas to Electricity with Local Carbon Capture (Retrofit Power Plant)	8.4	7.0	76.9	83.7	6.6	6.0	89.5	96.2
Ethanol Fermentation	0.9	0.9	42.4	42.4	6.9	6.0	55.3	55.3
Natural Solutions	6.3	25.5	11.4	11.4	0.0	0.0	11.4	11.4
Geothermal Direct Air Capture	11.0	11.0	247.0	182.0	5.2	6.0	258.2	193.2
Solvent Direct Air Capture	65.8	45.9	235.0	190.0	2.0	8.8	245.8	200.8
Total Negative Emissions	**125**	**125**				**Total System Cost ($B/yr)**	**22.8**	**14.0**

Table 42. *Total Cost Results for Pyrolysis Priority Scenario, Negative + Avoided Emissions Basis*

	Quantity, 2025	Quantity, 2045	Conversion Cost, 2025	Conversion Cost, 2045	Transport Cost	Storage Cost	Total Avg Cost, 2025	Total Avg Cost, 2045
Pathway	million tons CO_2 neg +avoided/yr	million tons CO_2 neg +avoided/yr	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided
Gasification of Dry Municipal Solid Waste to Liquid H_2	28.4	30.2	8.2	8.2	5.4	2.0	15.5	15.5
Fast Pyrolysis of Sawmill Residue and Shrub & Chaparral to Liquid Fuels	13.0	13.0	19.0	-9.0	9.3	1.2	29.5	1.5
Fast Pyrolysis of Forest Management to Liquid Fuels	22.4	22.4	37.8	9.7	8.2	1.2	47.1	19.0
Fast Pyrolysis of Low Moisture Agricultural Residue to Liquid Fuels	13.0	15.8	72.6	41.2	7.1	1.3	81.0	49.6
Biogas to Electricity with Local Carbon Capture (Retrofit Power Plant)	15.9	7.0	34.4	83.7	6.6	6.0	47.0	96.2
Ethanol Fermentation	0.9	0.9	42.4	42.4	6.9	6.0	55.3	55.3
Natural Solutions	6.3	25.5	11.4	11.4	0.0	0.0	11.4	11.4
Geothermal Direct Air Capture	11.0	11.0	247.0	182.0	5.2	6.0	258.2	193.2
Solvent Direct Air Capture	65.8	45.9	235.0	190.0	2.0	8.8	245.8	200.8
Total Negative + Avoided Emissions	**177**	**172**				**Total System Cost ($B/yr)**	**22.8**	**14.0**

Table 43. *Total Cost Results for Combustion Priority Scenario, Negative Emissions Basis*

	Quantity, 2025	Quantity, 2045	Conversion Cost, 2025	Conversion Cost, 2045	Transport Cost	Storage Cost	Total Avg Cost, 2025	Total Avg Cost, 2045
Pathway	million tons CO_2 neg/yr	million tons CO_2 neg/yr	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg	$/ton CO_2 neg
Combustion of Dry Municipal Solid Waste to Electricity	15.1	16.1	32.0	32.0	8.7	6.0	46.6	46.6
Combustion of Sawmill Residue and Shrub & Chaparral to Electricity	13.6	13.6	46.4	46.4	13.9	6.0	66.2	66.2
Combustion of Forest Management to Electricity	23.4	23.4	64.2	64.2	13.8	6.0	84.0	84.0
Combustion of Low Moisture Agricultural Residue to Electricity	15.2	18.4	70.6	70.6	7.4	6.0	84.0	84.0
Biogas to Electricity with Local Carbon Capture (Retrofit Power Plant)	8.4	7.0	76.9	83.7	6.5	6.0	89.4	96.2
Ethanol Fermentation	0.9	0.9	42.4	42.4	6.9	6.0	55.3	55.3
Natural Solutions	6.3	25.5	11.4	11.4	0.0	0.0	11.4	11.4
Geothermal Direct Air Capture	11.0	11.0	247.0	182.0	5.2	6.0	258.2	193.2
Solvent Direct Air Capture	31.2	9.2	235.0	190.0	2.0	8.8	245.8	200.8
Total Negative Emissions	**125**	**125**				**Total System Cost ($B/yr)**	**16.2**	**10.1**

Table 44. *Total Cost Results for Combustion Priority Scenario, Negative + Avoided Emissions Basis*

	Quantity, 2025	Quantity, 2045	Conversion Cost, 2025	Conversion Cost, 2045	Transport Cost	Storage Cost	Total Avg Cost, 2025	Total Avg Cost, 2045
Pathway	million tons CO_2 neg +avoided/yr	million tons CO_2 neg +avoided/yr	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided	$/ton CO_2 neg+ avoided
Combustion of Dry Municipal Solid Waste to Electricity	23.2	16.1	15.8	32.0	8.7	6.0	30.4	46.6
Combustion of Sawmill Residue and Shrub & Chaparral to Electricity	20.8	13.6	23.4	46.4	13.9	6.0	43.3	66.2
Combustion of Forest Management to Electricity	35.9	23.4	35.0	64.2	13.8	6.0	54.8	84.0
Combustion of Low Moisture Agricultural Residue to Electricity	23.2	18.4	41.5	70.6	7.4	6.0	54.9	84.0
Biogas to Electricity with Local Carbon Capture (Retrofit Power Plant)	15.9	7.0	34.4	83.7	6.5	6.0	47.0	96.2
Ethanol Fermentation	0.9	0.9	42.4	42.4	6.9	6.0	55.3	55.3
Natural Solutions	6.3	25.5	11.4	11.4	0.0	0.0	11.4	11.4
Geothermal Direct Air Capture	11.0	11.0	247.0	182.0	5.2	6.0	258.2	193.2
Solvent Direct Air Capture	31.2	9.2	235.0	190.0	2.0	8.8	245.8	200.8
Total Negative + Avoided Emissions	**168**	**125**				**Total System Cost ($B/yr)**	**16.2**	**10.1**

Timeframes: 2025 and 2045

In the above tables, we show costs for both the 2025 and 2045 timeframes. The 2025 costs are derived from engineering analysis of current plant designs as well as biomass availabilities projected for that year. For both timeframes, we used current or recent estimates of transport and storage costs (although transport costs vary historically, we could not find support for any long-term trend in these). For the 2045 timeframe, we used biomass availabilities projected to 2045 and we applied technological learning to the direct air capture and fast pyrolysis technologies, where we judged the impact of learning to be substantial. All costs are adjusted to 2018 dollars.

Biomass gasification to hydrogen, although novel in its application to negative emissions, is basically an assemblage of mature technologies, since gasifiers and associated equipment are used extensively in other applications. The costs we have estimated for this pathway are nth plant costs for existing technology and, although we expect some learning on plant design and integration in the future, we don't expect capital costs to drop substantially with deployment in California.

Pyrolysis to liquid fuels is a less mature technology, and arguably more likely to benefit from technological learning. Our estimates apply technology learning to forecast the capital cost for pyrolysis units in 2045. Thus, the 2045 costs for pyrolysis are lower than those in 2025. As well, the transport and storage costs are set constant.

Biomass combustion to electricity is considered relatively mature, since it is already practiced commercially. The costs we have estimated for this pathway are nth plant costs for existing technology. The difference between the 2025 and 2045 scenarios for combustion is the avoided emissions considered – in 2045, electricity is mandated to be carbon neutral, so there are no avoided emissions benefits to producing electricity, whereas in 2025 the electricity is assumed to displace electricity produced from natural gas.

Cost Curves

Using the values in the above tables, we constructed cost curves for the six cases in 2045. These are shown in Figure 77 to Figure 82. Corresponding cost curves for 2025 can be found in Appendix F. The charts show the quantity of CO_2 removed and average cost for each pathway in the set, in order of lowest to highest average cost. The result is similar to a long run total cost curve or supply curve from economic analysis. The results suggest that, to achieve a rate of negative emissions on the horizontal axis, society would have to bear an annual cost equal to the area of the bars to the left of that

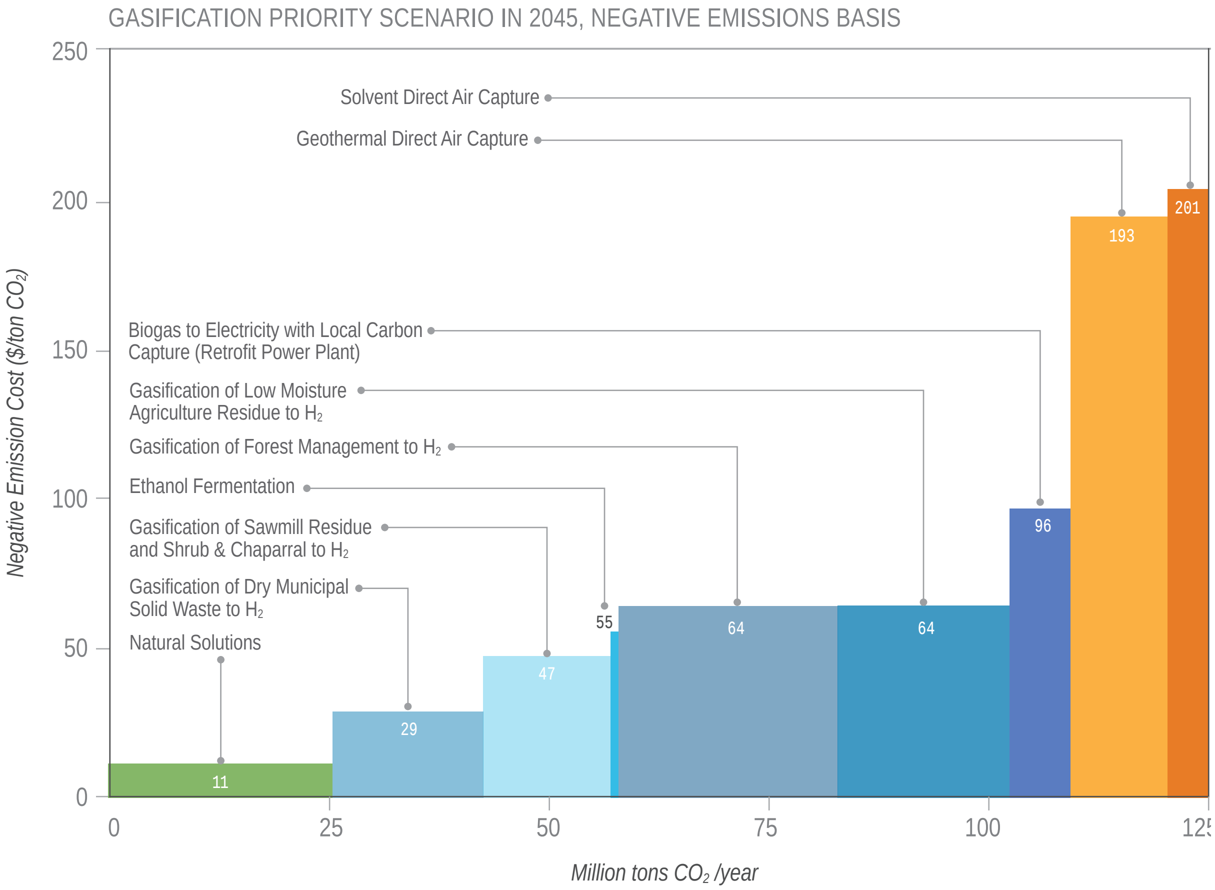


Figure 77. Total cost curve for Gasification Priority Scenario, 2045, negative emissions basis. *This scenario prioritizes the production of hydrogen over liquid fuel and electricity. Total (integrated) system cost for this scenario is $8.1B/year.*

GASIFICATION PRIORITY SCENARIO IN 2045, NEGATIVE + AVOIDED EMISSIONS BASIS

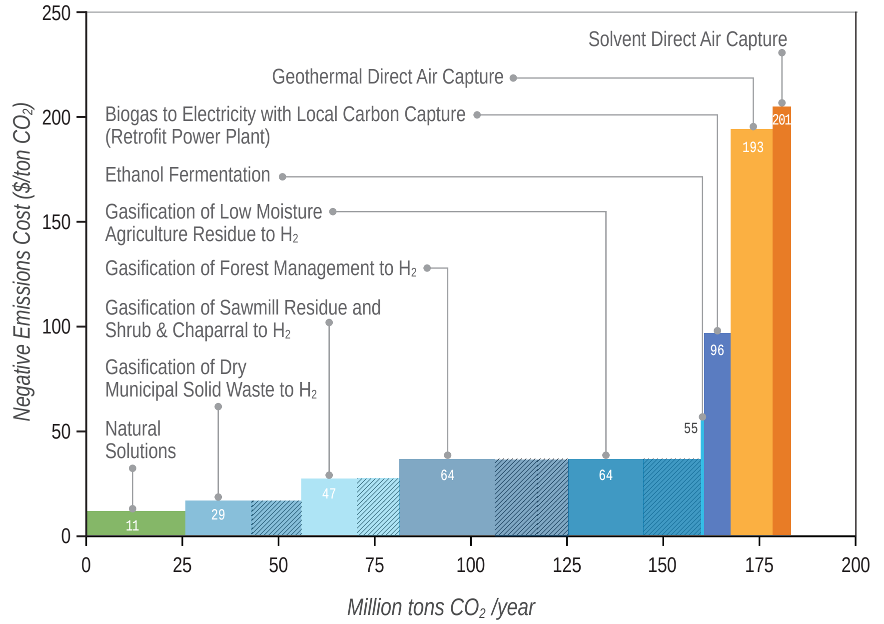


Figure 78. Total cost curve for Gasification Priority Scenario, 2045, negative and avoided emissions basis. *Hatched areas represent avoided emissions, most of which assume 1:1 replacement of continued use of fossil fuel. Total (integrated) system cost for this scenario is $8.1B/year.*

PYROLYSIS PRIORITY SCENARIO IN 2045, NEGATIVE EMISSIONS BASIS

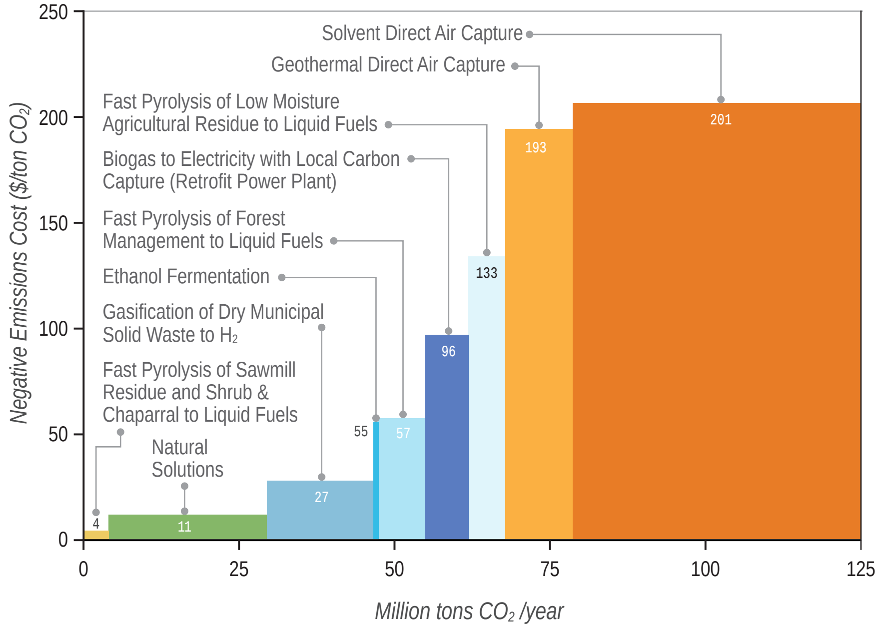


Figure 79. Total cost curve for Pyrolysis Priority Scenario, 2045, negative emissions basis. *This scenario prioritizes the production of liquid fuel over hydrogen and electricity. Total (integrated) system cost for this scenario is $14.0B/year.*

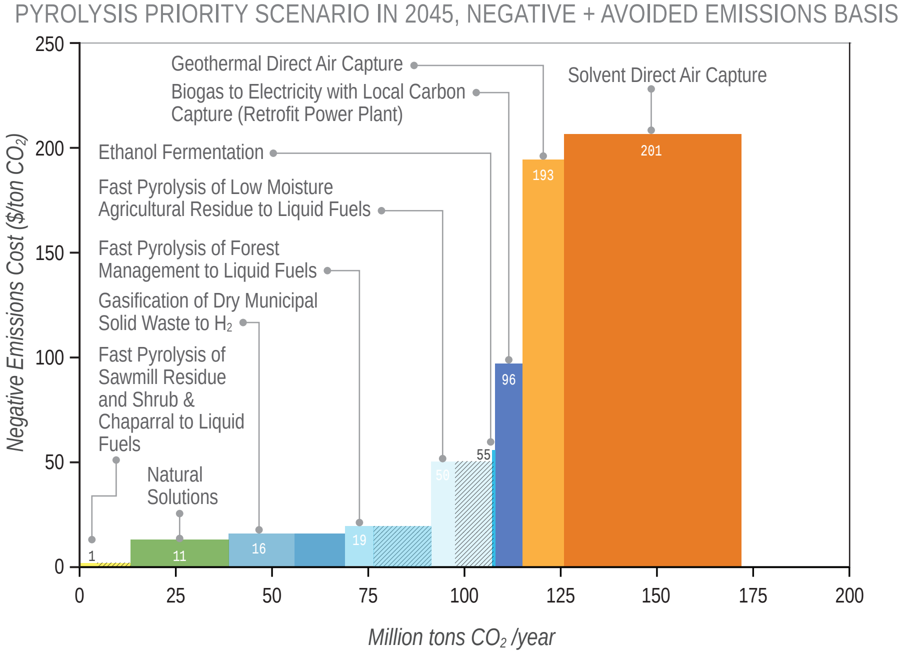


Figure 80. Total cost curve for Pyrolysis Priority Scenario, 2045, negative and avoided emissions basis. *Hatched areas represent avoided emissions, most of which assume 1:1 replacement of continued use of fossil fuel. Total (integrated) system cost for this scenario is $14.0B/year.*

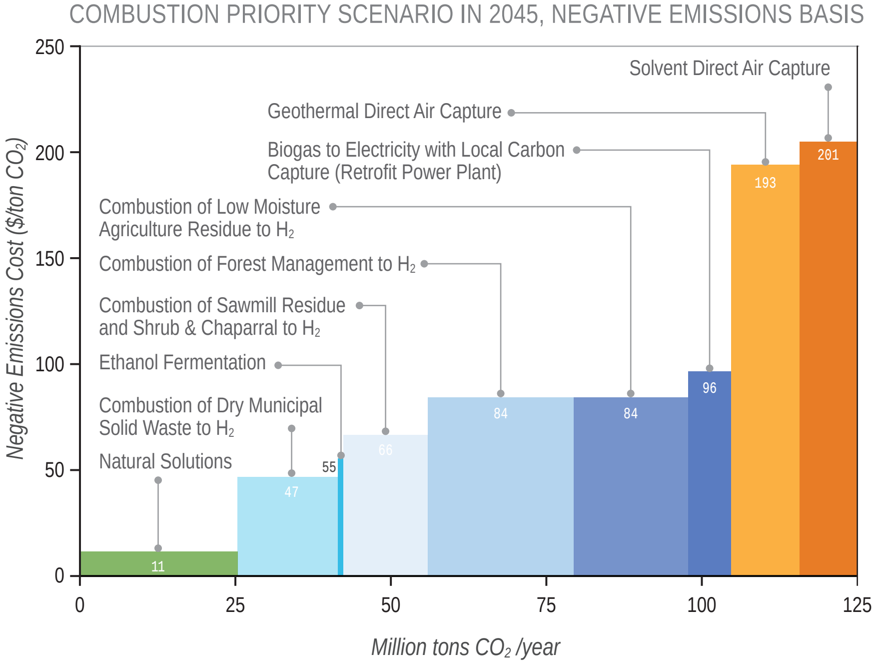


Figure 81. Total cost curve for Combustion Priority Scenario, 2045, negative emissions basis. *This scenario prioritizes the production of electricity over hydrogen and liquid fuel. Total (integrated) system cost for this scenario is $10.1B/year.*

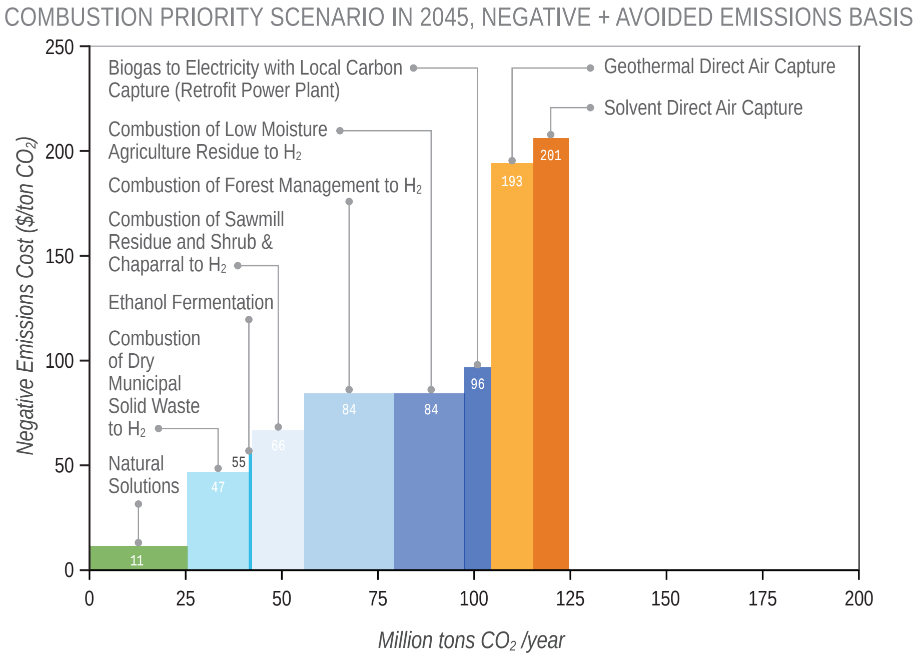


Figure 82. Total cost curve for Combustion Priority Scenario, 2045, negative and avoided emissions basis. *No avoided fossil electricity emissions are assumed for 2045 so the cost curve is identical to the negative emissions basis in Figure 81. Total (integrated) system cost for this scenario is $10.1B/year.*

cost. For example, for the Gasification Priority Scenario shown in Figure 77, the state can achieve 109 million tons of CO_2 per year using natural solutions and biomass conversion alone.

The cost curves are also plotted on a combined negative and avoided emissions basis. As described in more detail in Chapter 4, we have considered the emissions associated with fossil resources that may be avoided due to their displacement by fuels and energy from biomass sources, using the reference values in Table 21. We do not account for changes in avoided emission that are possible due to alternative uses or fates of the biomass. We assume that liquid fuels or hydrogen from biomass will replace a fossil-derived product; we also assume that there will be no carbon-emitting electricity to displace in 2045, and so there are no avoided emissions associated with electricity production from biomass sources. The cost of many pathways are lower when including avoided emissions than on the basis of CO_2 removed from the atmosphere alone, but the total system cost remains the same.

The system total quantity of CO_2 removal, 125 million tons per year, has been chosen to roughly match the expected residual emissions in California in 2045 so that, in net, the state becomes carbon neutral. In this report, we have not estimated or accounted for what those residual emissions are. However, some of the residual emissions are very likely to include legacy vehicles burning liquid fossil fuels and distributed uses of fossil natural gas that might be displaced by hydrogen. In these cases, the substantial avoided emissions from the Gasification or Pyrolysis scenarios would reduce the residual emissions: less than 125 million tons per year of removal would be needed. Hence, the system cost might be much lower and solvent direct air capture may not be needed at all if the avoided emissions and residual emissions are reconciled. We did not evaluate these cases here.

These charts differ from formal supply curves in two respects. First, each bar here represents the average of a distribution of costs. Some implementations of gasification of agricultural residue, for example, are actually lower cost than some implementations of municipal solid waste gasification. In a formal supply curve, the pathways would be mixed at the plant or feedstock level to give a smoother curve. However, we have consolidated pathways here for clarity.

Second, these charts differ from supply curves because there is not a single, fungible market for negative emissions. If such a market were created, a given market clearing price would not achieve exactly the quantity indicated because each pathway requires specific infrastructure and long-term investment. The pathways are inter-dependent in their use of transport and storage infrastructure and in their sharing of conversion facilities across biomass types.

The cost curves are best used as a tool for assessing the negative emissions pathways required and total system cost required to achieve full deployment. Intermediate cost and supply values are only suggestive.

Total System Cost

The cost curves above can be integrated to give the total cost to achieve 125 million tons per year of negative emissions.

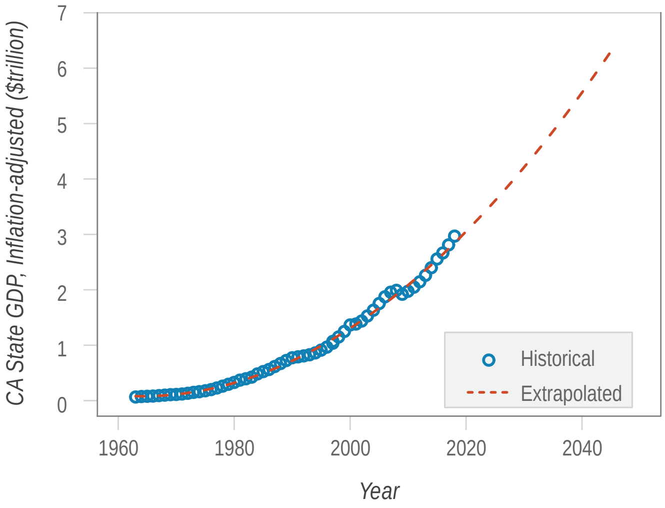


Figure 83. *California State Gross Domestic Product, historical and extrapolated to 2045. Extrapolation is a second-order polynomial fit. Source for historical data: U.S. Department of Commerce. (2019)*

The results are shown in Table 45 in both absolute costs and cost per unit of CO_2. In the context of negative emissions technologies, and of non-negative means to approach carbon neutrality, these costs are very modest. The average cost for the Gasification Priority Scenario of $65 per ton CO_2 is on the low end of literature estimates for the two most-studied negative emissions pathways: bioenergy with carbon capture and storage and direct air capture, which both range to the hundreds of dollars per ton [3].

Compared with the state's economic activity these total costs are also small. California's historic and extrapolated Gross Domestic Product is shown in Figure 83. The Gasification Priority Scenario amounts to 0.3% of the current Gross Domestic Product, and the Pyrolysis Priority Scenario comes to 0.5%. By 2045, the state Gross Domestic Product could reasonably double, giving system costs in 2045 of 0.1 and 0.2% of Gross Domestic Product, respectively.

The total cost here is the sum of all private costs that must be borne to achieve the scenario indicated. The programmatic costs to achieve these scenarios could be much higher or lower than these totals, depending on how the program is implemented. However, for rough comparison, the gasification scenario cost of $8.1 billion per year amounts to 6% of current state spending.

Total System Cost Sensitivity to Product Price

As discussed in Chapter 4 for individual technologies, the selling prices of the coproducts considered in this report have a strong impact on the economics of the various pathways. Here, we consider how the total system cost varies as the product wholesale price changes in Figure 84 to Figure 86. Contour lines on the plots show the total system cost in billions of dollars per year as a function of the wholesale prices of the products. The gasification scenario is dependent on the selling price of hydrogen and electricity; the pyrolysis scenario is dependent on the selling price of hydrogen, liquid fuels, and electricity; and the combustion scenario is only dependent on the selling price of electricity. Two technology scenarios are shown on each plot, and the tradeoff in product prices also allows us to define where each of the two scenarios is preferred. For example, in Figure 84, the thick diagonal line depicts the pairs of liquid fuel and hydrogen prices where the Gasification Priority Scenario and Pyrolysis Priority Scenario have the same total system cost. To the left of the line, the Pyrolysis Priority Scenario is the lower cost option, and to the right of the line, the Gasification Priority Scenario is lower cost. Numbered lines depict the total system cost in $billion per year for the pairs of prices falling along the line.

Table 45. *Total System Costs in 2045 for 125 million tons of CO_2 removed from the atmosphere.*

Scenario/Basis	Total Mitigation ($Mt\ CO_2/yr$)	System Total Average Cost ($/ton CO_2)	System Total Cost ($billion/yr)
Gasification Priority Scenario — negative emissions basis	125.0	65	8.1
Gasification Priority Scenario — avoided emissions basis	183.2	44	8.1
Pyrolysis Priority Scenario — negative emissions basis	125.0	112	14.0
Pyrolysis Priority Scenario — avoided emissions basis	171.6	82	14.0
Combustion Priority Scenario — negative emissions basis	125.0	81	10.1
Combustion Priority Scenario — avoided emissions basis	125.0	81	10.1

$Mt\ CO_2$ = million tons of CO_2

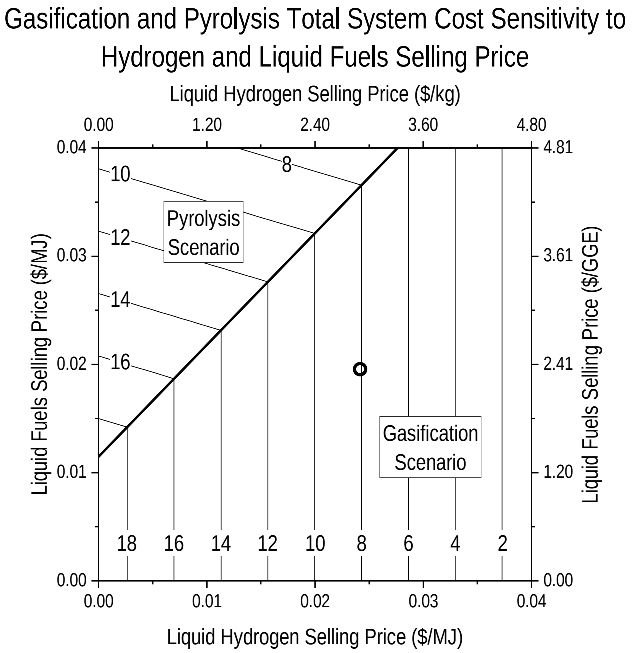

Gasification and Pyrolysis Total System Cost Sensitivity to Hydrogen and Liquid Fuels Selling Price

Figure 84. *Total system cost sensitivity to liquid hydrogen and liquid fuels selling prices, for gasification and pyrolysis scenarios. The heavy line indicates where the two technology scenarios have equal total system cost; the less expensive scenario is shown otherwise. Contour lines show the total system cost in $billion per year. The circle shows the value indicated in our cost curves, at the base case selling prices used in this report, $2.90/kg for liquid hydrogen and $2.35/GGE (gallon of gasoline equivalent) for liquid fuels.*

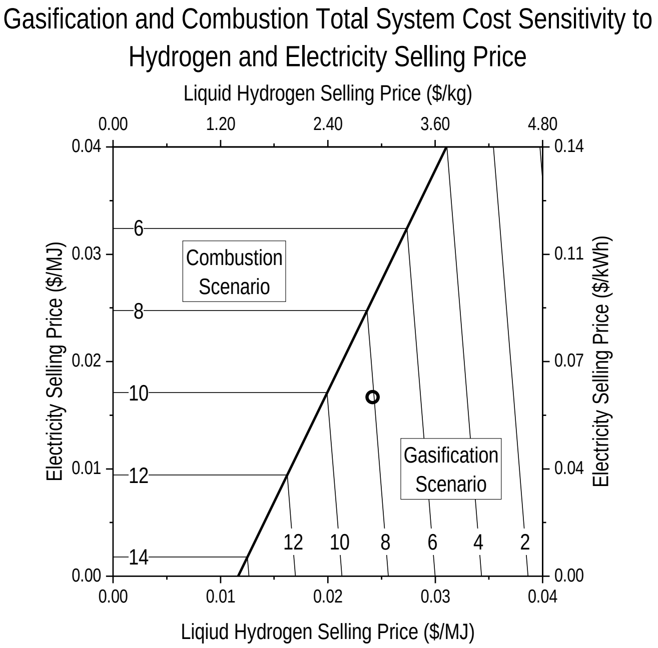

Gasification and Combustion Total System Cost Sensitivity to Hydrogen and Electricity Selling Price

Figure 85. *Total system cost sensitivity to liquid hydrogen and electricity selling prices, for gasification and combustion scenarios. The heavy line indicates where the two technology scenarios have equal total system cost; the less expensive scenario is shown otherwise. Contour lines show the total system cost in $billion per year. The circle shows the value indicated in our cost curves, at base case selling prices used in this report, $2.90/kg for liquid hydrogen and $0.60/kWh for electricity.*

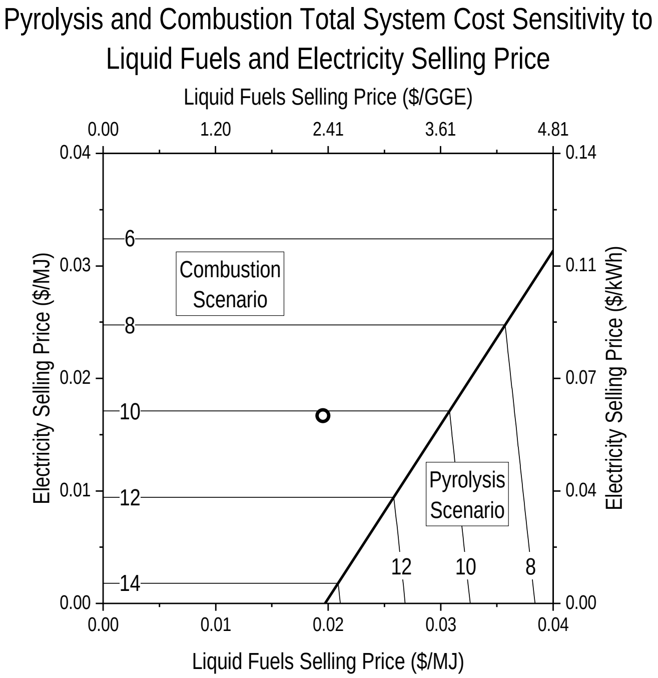

Pyrolysis and Combustion Total System Cost Sensitivity to Liquid Fuels and Electricity Selling Price

Figure 86. *Total system cost sensitivity to liquid fuels and electricity selling prices, for pyrolysis and combustion scenarios. The heavy line indicates where the two technology scenarios have equal total system cost; the less expensive scenario is shown otherwise. Contour lines show the total system cost in $billion per year. The circle shows the value indicated in our cost curves, at the base case selling prices used in this report, $2.35/GGE (gallon of gasoline equivalent) for liquid fuels and $0.60/kWh for electricity.*

Total System Cost Sensitivity to Biomass Availability and Direct Air Capture Cost

Aside from sale prices of coproducts, the most important uncertain factors that influence total system cost are the quantity of biomass available and the price of direct air capture. Our assessment of biomass availability is aggressive because we use full technical potentials for some categories of biomass. Because of the dispersed and varied sources of biomass, practical availability may be lower. On the other hand, we have not included any dedicated energy crops, which could increase the availability substantially. The cost of direct air capture has long been debated in the literature and, although the costs are becoming more certain as the technology becomes commercial, some recent assessments still estimate costs higher than what we have used. Companies developing the technology claim the costs will be lower than what we have used.

Biomass availability and direct air capture cost are related in their influence on total system cost, and each influences it strongly under certain circumstances. In the Gasification Priority Scenario, very little direct air capture is required, so the cost of direct air capture doesn't matter much.

Similarly, at low costs of direct air capture, biomass availability doesn't change the total system cost much, because any shortfalls can be made up with direct air capture at a similar price. However, if the cost of direct air capture is high, the total system cost is very sensitive to biomass, because one ton less of CO_2 from biomass means one ton more of expensive direct air capture.

The combined effects of these two factors are shown in the contour plots in Figure 87. Each plot shows the total system cost for a given scenario for a range in biomass availability and direct air capture cost. For the purposes of this calculation, all categories of biomass, including biogas, are scaled proportionally to give the totals shown on the vertical axes. The numbered lines depicts the pairs of values that give the total system cost shown, in $billion per year.

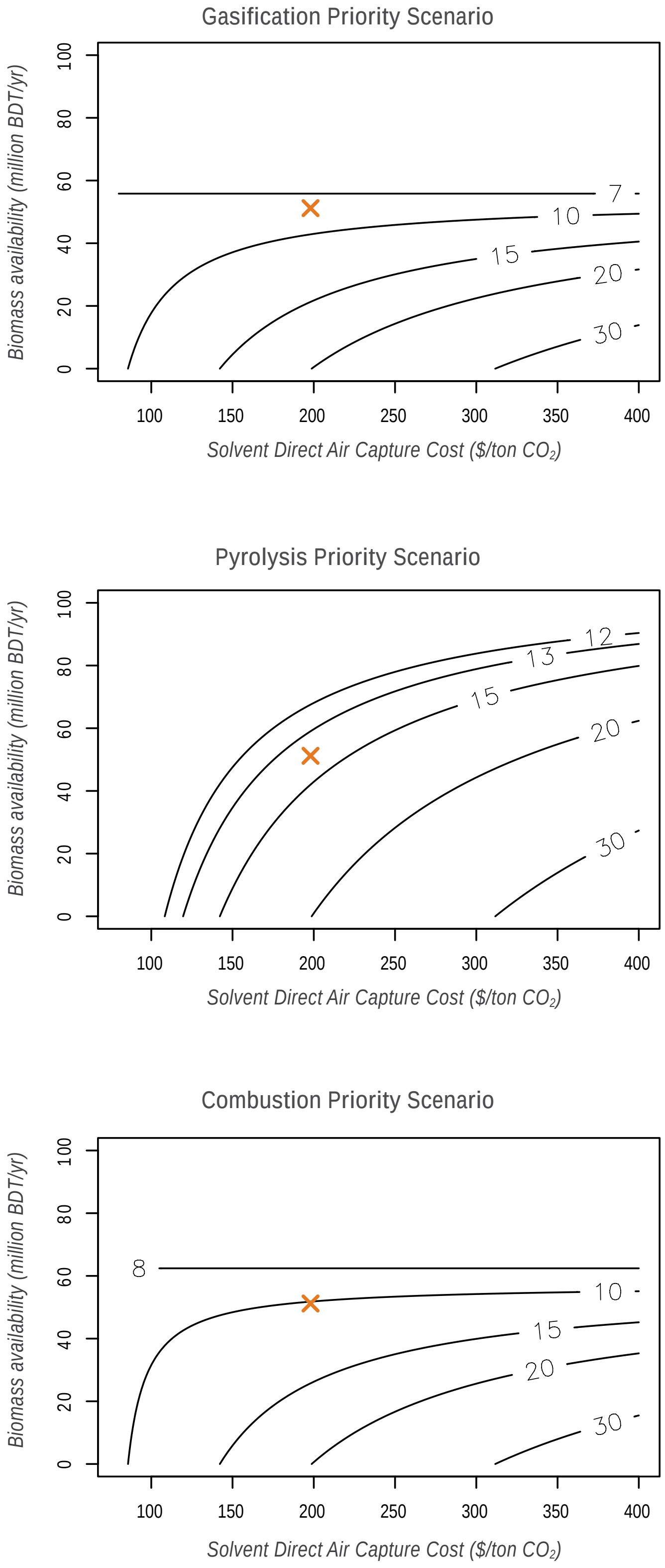


Figure 87. *Dependence of total system cost on biomass availability and cost of direct air capture. In these contour plots, the labeled curves show the total system cost in $billion/yr for the direct air capture costs and total biomass availability shown on the x and y axes. Red 'x's show the base case assumptions for these values.*

Conclusions

In this chapter, we have estimated the cost to remove 125 million tons per year of CO_2 from the atmosphere in California. We call this the total system cost of the negative emissions system. Combined with conventional climate mitigation measures, the resulting system is expected to meet the state's goal of being carbon neutral by 2045. Our best estimate of the total system cost is $8.1 billion per year, which makes full use of the lowest-cost technology pathways and available waste biomass. We also evaluated the most important uncertain factors that determine the total system cost, including the type of energy coproducts, the value of energy coproducts, total availability of biomass, and the cost of solvent direct air capture. We showed the effects on total system cost of changing each of these factors, and found the results mostly lie in the range of $5–15 billion per year for reasonable sets of inputs. These costs are quite moderate compared with the state's economic output and with many previous estimates of the cost of negative emissions.

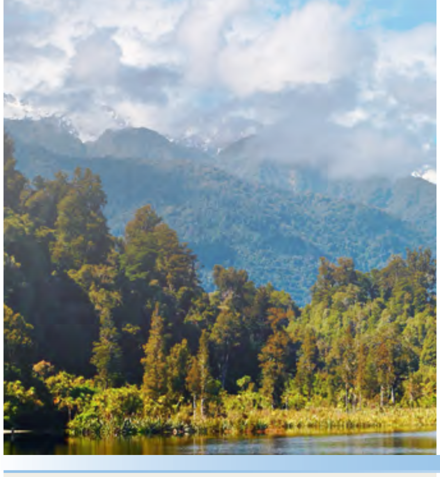
Scenarios can certainly be constructed where the total system cost reaches $20 or $30 billion per year. However, these scenarios can easily be avoided by policymakers and private investors who are working to minimize costs. If it turns out, for example, that hydrogen is much less valuable in the future market than we have assumed, investors can shift their focus to electricity-generating plants and avoid substantially higher system costs. If it turns out that forest biomass is much less available than we assume, policymakers can invest more heavily in direct air capture to drive down the cost of that technology through learning.

We presented three different scenarios to emphasize production of different co-products: gasification to maximize hydrogen production, pyrolysis for liquid fuel, and combustion for electricity. In terms of cost and emissions, we find the hydrogen scenario is clearly favorable above the others, however policymakers and investors may wish to pursue the other scenarios, or a mix of the three, for reasons beyond the economics of CO_2 removal. The success of the gasification scenario, for example, depends largely on the value of hydrogen as a transportation fuel. This, in turn, depends on development of hydrogen infrastructure and vehicles. These developments may be pursued or not for reasons that are outside the scope of the negative emissions system. If not, investors and policymakers would want to lean more heavily on electricity and liquid fuel coproducts than hydrogen.

On an energy basis, electricity is the least valuable of the coproducts we assessed. The falling costs of renewable electricity may make the combustion scenario even less attractive to investors in the future. However, the high penetration of intermittent renewable electricity in 2045 may make baseload and dispatchable electricity – that is also carbon neutral – much more valuable at that time. Policymakers that want these assets in the electricity system may wish to favor combustion of biomass for electricity or some variation.

Liquid fuels for aircraft and legacy vehicles are very likely to be used to some degree in 2045. If there is value to producing these fuels in-state rather than increasing imports of biofuel or relying on negative emissions to offset fossil fuels, and investors may wish to pursue pyrolysis to liquid fuel, despite its higher cost and lower productivity as a negative emissions technology.

Overall, we find considerable flexibility among the technology pathways and scenario options. With active policy and investment, there are many routes to carbon neutrality with CO_2 removal costs below $10 billion per year, which can easily be considered a bargain for California to lead the world in climate mitigation.



CHAPTER 10

Additional Approaches that May Improve California's Negative Emissions Potential

SUMMARY

Our evaluation of negative emissions technologies focused on those that are well-enough developed for us to estimate their costs and available volumes. These are by no means the only options that California will have available in 2045. Two important topics appear likely to be contributors to California's negative emissions ambitions: carbon mineralization, and new biomass sources, including algae. In addition, there are a large number of biomass conversion technologies and direct air capture approaches that we did not consider for simplicity.

Carbon Mineralization

First, we can look at how the Earth controls CO_2 in the atmosphere, and how we might speed it up. Limestone, or calcium carbonate, $CaCO_3$, is the most stable solid form of CO_2 in the earth. Its stability is attested by its use to construct buildings, particularly beautiful facades. But even as the most stable solid form of a CO_2-containing substance, it will still dissolve slowly in rainwater and turn into bicarbonate, HCO_3^-, in solution, which is even more chemically stable than limestone and is one of the most important ions in seawater. Marine organisms use bicarbonate to form their shells and solid structural elements (like coral).

Bicarbonate and calcium carbonate come from the weathering of rocks containing calcium. These rocks tend to come from deep in the earth and are brought to the surface by volcanism (in basalt like that found in Hawaii) or faulting and plate tectonics, which can bring up large slabs of rock from deep in the earth called **ultramafic rocks**. Such rocks are very common in California (Figure 88), and appropriately the California state rock is serpentinite, a common ultramafic rock. These rocks are dissolved readily by seawater for the same reason that CO_2 is absorbed by a sodium hydroxide solution—the calcium dissolves to form calcium hydroxide, which reacts by the same mechanisms as sodium hydroxide, forming calcium ions and bicarbonate in rivers that empty into the ocean. There the bicarbonate builds up until marine organisms like corals precipitate it into their homes and bodies, which eventually turn into limestone rock, permanently

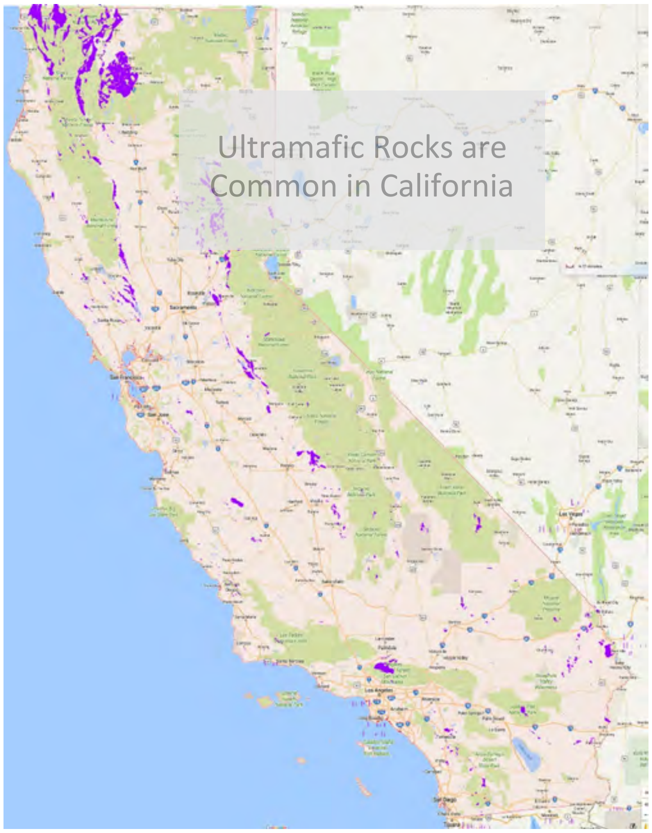


Figure 88. Location of the ultramafic rocks in California, shown in purple, as seen at the surface. *From the California Geologic Survey.*

storing the CO_2. This natural cycle of CO_2 in the air reacting with rocks, forming calcium and bicarbonate ions that travel to the ocean in rivers, where they eventually precipitate into solid calcium carbonate shells and skeletons that accumulate on the ocean bottom and turn into limestone rock, has been the primary control on the average amount of CO_2 in the atmosphere throughout time. (This process does not acidify the ocean, because the acidity of the CO_2 was neutralized by the base in the rock—ocean acidification occurs when CO_2 in the air dissolves directly into the ocean, turning into carbonic acid.)

Researchers are examining whether this process can be speeded up, either by circulating water through rocks and dissolving the calcium or by grinding up calcium-rich rocks and reacting them with air and rainwater [see Kelemen et al. 2018 [253] for a current review]. This is an attractive approach because it mimics the processes already active in the earth and, most importantly, uses very little added energy because the reaction of CO_2 with dissolved calcium hydroxide actually releases energy (heat). There is no need to heat the solutions up again, as the direct air capture facilities must do to recover pure CO_2, because in this **carbon mineralization** or **enhanced weathering** approach the CO_2 forms either solid calcium carbonate or dissolved bicarbonate like that already in the ocean.

Much needs to be worked out before the benefits of this approach can be estimated, but since ultramafic rocks are found in a wide variety of locations, including California, it is worth pursuing. Current estimates are that enhanced weathering is less expensive than direct air capture and could be quite inexpensive. Since it is still quite uncertain, we estimate that the costs would be from \$50 to \$200 per ton removed. The capacity is more likely to be controlled by local factors than overall amount of rock available, since there are thousands of cubic kilometers of this rock in California, and one cubic kilometer fully reacted would absorb one billion tons of CO_2. An important constraint is that these rocks often contain small amounts of asbestos. This mineral tends to be quickly destroyed by damp air but ensuring that any operations accessing ultramafic rock do not release asbestos will be vital. It is encouraging that the San Francisco Water Department [254] has just completed a major reconstruction of the Calaveras Dam near Fremont, CA, that involved the movement of 7 million cubic yards of rock, including serpentinite, that included small amounts of naturally occurring asbestos. Their extensive control and monitoring programs were able to ensure that asbestos levels stayed well below safety limits and were not a health and safety problem.

Other Biomass Sources

We have studiously avoided considering anything but waste biomass in this report – but of course there may be appropriate options for adding biomass supply to our current sources. The difficulty of many energy crop schemes is that they replace food crops on agricultural land. Perennial grasses that could be grown without irrigation water are one potential source of biomass that does not replace food. The California State Grass, Purple Needlegrass, has been largely lost from our grasslands, replaced by annual grasses of European origin. One option being investigated in Missouri [255] is to use native prairie grasses as feedstock for anaerobic digesters, mowing the mixture just as grazers like bison would have in natural prairies, and converting that biomass into renewable natural gas. An additional advantage is that perennial grasses tend to increase soil carbon due to their deep and long-lived root systems. There is no current evaluation of the potential to use California native grasses in approaches like this.

Algae has been extensively studied by the United States Department of Energy as a means to produce biofuels, and the processes and procedures are well established. The Billion Ton Report outlines many of those additional possibilities, including algae grown on and offshore. The Salton Sea region is a likely location for commercial algae production in California. We have not attempted to quantify the costs for this approach due to the currently small volume of algae cultivation in California, and the limitation that we placed upon ourselves to only consider waste resources.

It is beyond the scope of this report to attempt to evaluate the benefits or tradeoffs of grown-for-purpose biomass products, but there is clearly both space for beneficial development, and concern over the impacts that such approaches would have, particularly in terms of land use.

Other Technologies

The general nature of this report, and the broad variety of biomass resources in California, have encouraged us to focus on thermal conversion technologies for biomass. However, there are also successful biologically-based technologies that either convert biomass to fuel (cellulosic ethanol and drop-in fuels, for instance [256] or syngas to fuels through biological mediation [122], [257]. These technologies have bright futures and may be directly applicable to the conversion of California biomass. In general, their costs are in line with the conversion technologies we considered, and our choice to not consider them explicitly was merely for expediency and does not reflect any evaluation of their prospects or costs.

A large number of research institutions are considering new methods for direct air capture. We have not attempted to evaluate their potential costs or prospects, because we did not have adequate information to attempt a full system analysis (recognizing that the systems we considered are also constrained by limited data). We fully expect that a broad range of technologies will be applied in California's quest for carbon neutrality and hope that California's business and policy environment creates a radical incubation circumstance where new technologies rapidly increase efficiency, maximize carbon capture, and drive down system costs.

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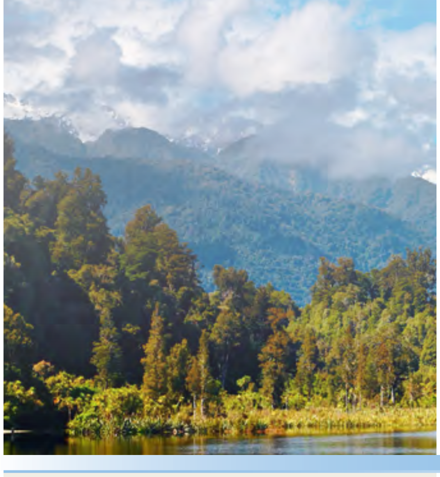

Appendix

Getting to Neutral: Options for Negative Carbon Emissions in California

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Appendix A: Standardized Units List, Definitions, and Abbreviations

Abbreviation	Definition
BECCS	bioenergy, carbon capture and storage
BDT	bone dry metric tons (0% moisture)
BTU	British thermal units
CAPEX	capital expense
CARB	California Air Resource Board
CCS	carbon capture and storage
CHP	combined heat and power
CLCFS	California Low Carbon Fuel Standard
CO_2e	carbon dioxide equivalent
COMET	Carbon Management and Emissions Tool
CPUC	California Public Utilities Commission
CRF	Capital recovery factor
DOE	United States Department of Energy
EGR	enhanced gas recovery
EIA	United States Energy Information Administration
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
FVS	Forest Vegetation Simulator
g	gram
GDP	Gross Domestic Product
GHG	greenhouse gas emissions
GWP	global warming potential
ha	hectare
H_2	hydrogen
IPCC	Intergovernmental Panel on Climate Change
$ktCO_2/yr$	kiloton of carbon dioxide per year
kg	kilogram
km^2	square kilometer
kWh	kilowatt hour
LCFS	Low Carbon Fuel Standard
LSNG	liquid solvent direct air capture using natural gas
LLNL	Lawrence Livermore National Laboratory
MJ	megajoule
MWth	Megawatt thermal
MW	megawatts
MWh	megawatt hour
OPEX	operating expense
RD&D	research, development and demonstration
SOC	soil organic carbon
SSGT	low temperature solid sorbent direct air capture using geothermal heat
SSHP	low temperature solid sorbent direct air capture using an additional heat pump
SSJB	San Joaquin Basin
SSPV	solid sorbent direct air capture with solar photovoltaic energy and battery storage
SSWH	low temperature solid sorbent direct air capture using waste heat
$tC\ ha^{-1}\ y^{-1}$	metric tons of carbon per hectare per year
tCO_{2_e}	metric tons of carbon dioxide equivalents
t-mi	metric ton-mile
tCO_2	metric tons of carbon dioxide
tCO_2/yr	metric tons of carbon dioxide per year
Tons	metric tons
Tons Biogas	We use metric tons (of gas) for gaseous waste, based on the volume of biogas available and accounting for the molecular weight and composition of CO_2 and CH_4 in the biogas
TPD	metric tons per day
TRL	Technology Readiness Level
USDA	United States Department of Agriculture
USFS	United States Forest Service
V/V	volume per unit volume
W/V	weight per unit volume
yr	year

Appendix B: Biomass Feedstock County Tables

Table S1. *Interventions in Next 10 Study that Result in Negative Emissions.*

COUNTY	AGRICULTURE RESIDUE (BDT)
Alameda	3,149.61
Alpine	215.14
Amador	66,260.42
Butte	282,440.97
Calaveras	194,246.86
Colusa	620,681.92
Contra Costa	19,413.28
Del Norte	-
El Dorado	146,818.78
Fresno	2,197,968.39
Glenn	330,093.78
Humboldt	222.69
Imperial	2,327.39
Inyo	69,733.83
Kern	1,689,053.97
Kings	280,252.11
Lake	16,313.31
Lassen	283.31
Los Angeles	9,125.94
Madera	859,052.72
Marin	646.61
Mariposa	109.72
Mendocino	148,391.56
Merced	594,983.17
Modoc	8,420.08
Mono	3,064.14
Monterey	200,749.22
Napa	43,448.28
Nevada	369.81
Orange	25,529.42
Placer	11,357.72
Plumas	27,576.31
Riverside	159,574.75
Sacramento	57,920.78
San Benito	18,921.58
San Bernardino	6,209.78
San Diego	39,381.72
San Francisco	192,380.67
San Joaquin	761,331.75
San Luis Obispo	58,449.44
San Mateo	3,378.06
Santa Barbara	58,824.81
Santa Clara	16,181.83
Santa Cruz	18,949.25
Shasta	1,886.06
Sierra	27,395.47
Siskiyou	76,772.11
Solano	45,323.92
Sonoma	72,023.75
Stanislaus	1,351,205.47
Sutter	178,608.06
Tehama	104,457.31
Trinity	94,420.61
Tulare	730,326.11
Tuolumne	660.83
Ventura	295,960.11
Yolo	281,904.69
Yuba	109,627.75
Other	127,944.47
TOTAL	**12,742,321.58**

Table S2. *Municipal Solid Waste Biomass Feedstock Availability by California County 2045 in Bone Dry Metric Tons.*

COUNTY	MSW (BDT)
Alameda	500,680.22
Alpine	445.61
Amador	10,612.22
Butte	72,658.06
Calaveras	13,350.83
Colusa	8,792.58
Contra Costa	329,217.11
Del Norte	6,814.53
El Dorado	53,973.36
Fresno	348,087.00
Glenn	8,729.64
Humboldt	30,640.94
Imperial	91,052.44
Inyo	6,225.61
Kern	415,005.97
Kings	49,466.44
Lake	18,338.61
Lassen	8,429.64
Los Angeles	3,227,985.00
Madera	60,493.33
Marin	67,772.22
Mariposa	4,943.50
Mendocino	22,014.92
Merced	114,878.06
Modoc	2,003.78
Mono	6,821.42
Monterey	139,622.17
Napa	46,901.39
Nevada	27,595.06
Orange	1,060,736.31
Placer	127,608.11
Plumas	5,455.31
Riverside	893,920.33
Sacramento	511,170.81
San Benito	23,983.14
San Bernardino	732,207.75
San Diego	1,209,393.08
San Francisco	240,489.94
San Joaquin	310,821.72
San Luis Obispo	90,921.42
San Mateo	231,190.67
Santa Barbara	141,934.08
Santa Clara	569,462.78
Santa Cruz	70,824.11
Shasta	61,261.64
Sierra	889.92
Siskiyou	17,593.97
Solano	147,375.72
Sonoma	144,066.39
Stanislaus	137,928.22
Sutter	11,611.22
Tehama	18,754.03
Trinity	2,910.81
Tulare	55,621.00
Tuolumne	13,858.22
Ventura	300,647.72
Yolo	75,139.00
Yuba	56,770.22
Other	
TOTAL	**12,958,099.31**

Table S3. *Gaseous Waste Biomass Feedstock Availability by California County 2045 in Metric Tons.*

COUNTY	GASEOUS WASTE (TONS)
Alameda	168,987.65
Alpine	-
Amador	2,162.42
Butte	18,985.74
Calaveras	-
Colusa	-
Contra Costa	112,094.66
Del Norte	-
El Dorado	7,382.60
Fresno	228,181.98
Glenn	23,970.14
Humboldt	4,554.22
Imperial	11,513.82
Inyo	-
Kern	261,591.44
Kings	20,165.65
Lake	4,396.91
Lassen	-
Los Angeles	1,381,255.82
Madera	113,061.76
Marin	39,982.40
Mariposa	429.53
Mendocino	1,881.17
Merced	365,768.27
Modoc	-
Mono	-
Monterey	61,160.52
Napa	11,121.01
Nevada	3,947.88
Orange	455,729.64
Placer	30,130.96
Plumas	-
Riverside	232,757.67
Sacramento	182,339.32
San Benito	2,578.88
San Bernardino	217,793.09
San Diego	342,456.61
San Francisco	28,550.94
San Joaquin	242,491.00
San Luis Obispo	18,437.48
San Mateo	77,186.33
Santa Barbara	40,902.74
Santa Clara	208,714.13
Santa Cruz	29,496.07
Shasta	21,291.35
Sierra	-
Siskiyou	-
Solano	73,236.60
Sonoma	40,070.82
Stanislaus	245,491.58
Sutter	943.24
Tehama	11,034.13
Trinity	-
Tulare	644,944.35
Tuolumne	1,202.98
Ventura	59,323.87
Yolo	23,157.64
Yuba	27,629.02
Other	
TOTAL	**6,100,486.03**

Table S4. *Forest Biomass (Sawmill Residue, Shrub & Chaparral and Forest Management) Biomass Feedstock Availability by California County 2045 in Bone Dry Metric Tons.*

COUNTY	SHRUB & CHAPARRAL (BDT)	SAWMILL RESIDUE (BDT)	FOREST MANAGEMENT (BDT)
Alamoda	2,400.00	800.00	19,151.40
Alpine	3,700.00	55,100.00	27,669.39
Amador	5,300.00	46,100.00	82,164.52
Butte	4,700.00	117,100.00	495,405.09
Calaveras	26,800.00	78,700.00	277,452.68
Colusa	28,000.00	9,700.00	20,647.05
Contra Costa	2,400.00	100.00	15,307.52
Del Norte	1,200.00	170,100.00	289,869.80
El Dorado	15,000.00	233,800.00	572,430.35
Fresno	8,400.00	270,100.00	187,705.68
Glenn	14,900.00	32,100.00	99,947.58
Humboldt	3,100.00	583,300.00	2,415,131.37
Imperial	142,400.00		
Inyo	119,200.00	22,200.00	
Kern	158,000.00	32,200.00	112,197.84
Kings	1,000.00		
Lake	79,500.00	64,400.00	155,701.12
Lasson	221,200.00	203,100.00	348,686.97
Los Angeles	102,800.00	17,200.00	11,151.05
Madera	5,800.00	122,300.00	201,465.57
Marin	200.00	3,400.00	41,402.73
Mariposa	20,600.00	40,600.00	114,545.65
Mendocino	26,100.00	515,700.00	1,828,097.19
Merced	700.00		
Modoc	105,900.00	120,600.00	215,786.72
Mono	42,800.00	42,000.00	90,525.86
Monterey	26,900.00	12,000.00	116,967.74
Napa	30,500.00	13,200.00	78,854.06
Nevada	6,000.00	115,300.00	235,110.75
Orange	8,700.00	600.00	
Placer	5,500.00	136,200.00	382,885.26
Plumas	8,800.00	421,900.00	1,011,770.50
Riverside	219,400.00	7,400.00	1,275.17
Sacramento	100.00		
San Benito	16,200.00	3,000.00	31,380.09
San Bernardino	576,500.00	32,100.00	59,622.71
San Diego	202,100.00	9,000.00	26,416.58
San Francisco			
San Joaquin	400.00	300.00	7,688.06
San Luis Obispo	39,600.00	7,300.00	53,210.44
San Mateo	1,900.00	22,800.00	96,497.75
Santa Barbara	37,600.00	12,800.00	9,202.92
Santa Clara	21,800.00	10,600.00	84,113.92
Santa Cruz	4,900.00	51,800.00	270,927.83
Shasta	51,900.00	363,300.00	845,280.84
Sierra	6,600.00	128,800.00	388,656.57
Siskiyou	52,300.00	781,700.00	1,382,804.45
Solano	1,400.00	100.00	5,986.29
Sonoma	12,500.00	100,000.00	462,862.12
Stanislaus	6,000.00	800.00	1,410.57
Sutter			4,385.72
Tehama	33,100.00	151,700.00	315,641.38
Trinity	7,900.00	586,700.00	937,222.21
Tulare	6,600.00	194,900.00	80,554.45
Tuolumne	24,600.00	197,800.00	437,136.77
Ventura	15,100.00	15,400.00	9,891.22
Yolo	12,100.00	300.00	
Yuba	500.00	37,100.00	143,808.78
TOTAL	**2,579,600.00**	**6,195,600.00**	**15,104,008.26**

Appendix C: Direct Air Capture Supplementary Information

Table S5. *Fluid flow database (TDS: total dissolved solid)*

Source	Site	Type	City	County	Latitude	Longitude	Temp oC	Flow L/min	Depth m	TDS ppm	Plant size ktCO$_2$/yr
[1]	Casa Diablo Springs - Endogenous well #2	spring		Mono	37.646	-118.916	135	757			16.0
[2]	Calistoga Private and Commercial Industrial Low Temperature Geothermal Facility	Direct use			38.579	-122.580	135	398			8.4
[2]	Heber	colocated	Heber	Imperial	32.733	-115.533	168	8,500	1,531	20,000	270.5
[2]	Holtville	colocated	Holtville	Imperial	32.786	-115.249	204	2,400	1,829		104.4
[2]	El Centro	colocated	El Centro	Imperial	32.800	-115.567	168	8,500	1,531	20,000	270.5
[2]	Brawley	colocated	Brawley	Imperial	2.9833	-115.533	138	500	2,545	28,000	11.0
[2]	Calipatria	colocated	Calipatria	Imperial	33.133	-115.517	360	6,900	1,236	390,000	649.7
[2]	Niland	colocated	Niland	Imperial	33.233	-115.517	348	18,000	1,340	340,000	1,624.7
[2]	Mammoth Lakes	colocated	Mammoth Lakes	Mono	37.650	-118.967	177	15,792	487	1,530	548.6
[2]	Calistoga	colocated	Calistoga	Napa	38.583	-122.583	18	4,447	244	660	98.2
[2]	Middleton/Cobb	colocated	Middleton/Cobb	Lake	38.750	-122.617	100	68		7,770	0.7
[2]	Lower Lake	colocated	Lower Lake	Lake	38.917	-122.600	187	429	2,385	8,000	16.3
[2]	Wilbur Springs	colocated	Wilbur Springs	Colusa	39.033	-122.430	175	330	2,712	25,900	11.3
[2]	Wendel	colocated	Wendel	Lassen	40.300	-120.195	107	8,267	334	1,040	99.3
[2]	Drakesbad	colocated	Drakesbad	Plumas	40.421	-121.377	129	897	387	4,570	17.2
[2]	Canby	colocated	Canby	Modoc	41.450	-120.867	116	1,250	1,035	900	18.7
[2]	Mesa 6-2 U.S.B.R.	well		Imperial	32.786	-115.256	186	900	1,804		33.9
[2]	Mesa 6-1 U.S.B.R.	well		Imperial	32.786	-115.249	204	1,500	2,426		65.3
[2]	Sinclair 3	well		Imperial	33.147	-115.608	168	4,500	1,439	280,000	143.2
[2]	Elmore 1 Well	well		Imperial	33.183	-115.612	360	2,400	2,169		226.0
[2]	IID 2 - Imp. Therm. Pr.	well		Imperial	33.197	-115.599	348	3,300	1,776	260,000	297.9
[2]	Napa Val. Sps. Bottle Co.	well		Napa	38.583	-122.576	104	49	63	719	0.5
[2]	Sunedco/Bailey Min. 1	well		Colusa	39.033	-122.430	175	197	2,712		6.7
[2]	Magma Power Amedee 1 2	well		Lassen	40.300	-120.195	107	227	334		2.7
[2]	Magma Energy Wells	well		Modoc	41.672	-120.217	160	1,370	1,508		40.0

Appendix D: Thermal Conversion Technologies Cost Calculations

We calculated the cost of producing negative CO_2 emissions from biomass conversion technologies in terms of dollars per ton CO_2 equivalent. In most cases, our negative emissions are purely CO_2; in scenarios that produce biochar, we assume that 80% of the carbon remains in the soil for 100 years to calculate CO_2 equivalents. All costs are scaled to 2018 dollars using the Chemical Engineering Plant Cost Index.

Base capital costs for biomass conversion technologies were obtained from literature references. To these base costs, we added units as necessary for CO_2 capture, drying, compression, and temporary on-site storage, and other process units depending on the product. The capital costs and scaling factors for these units were based on Quality Guidelines from the National Energy Technology Laboratory, the National Renewable Energy Laboratory, and the Department of Energy Hydrogen and Fuel Cell Technology Office.[3]–[6] The equations for the scaled capital costs and operating electricity consumption are listed in Table S6.

The total capital cost (CAPEX) was assumed to be repaid over a twenty-year plant life with an internal rate of return of 10%, leading to an overall annual capital charge factor (CCF) of 15%. Fixed operating cost (OPEX) and variable operating cost based on the individual scenario and the collection cost of the specific biomass type were added to calculate the total annualized cost (Equation S1).

Product revenue is calculated based on the amount of fuel or chemical produced in the individual scenario and the current wholesale price for the product. The total annualized OPEX after product revenue is divided by the annual negative emissions to calculate the cost to capture CO_2 (Equation S2).

We make the following common assumptions in calculating costs:

- Plant life: 20 years
- Internal rate of return: 10% of capital per year
- Capital charge factor: 15% of capital per year
- Fixed operating & maintenance cost: 4.5% of capital per year
- Operational for 90% of the year
- Weighted average cost of forest biomass: $40 per bone dry ton
- Weighted average cost of agricultural residue: $60 per bone dry ton

Table S6. *Scaled capital cost and operating electricity consumption for equipment related to CO2 capture, drying, compression, and storage, and hydrogen liquefaction. These values were added to the base costs for technologies and processes obtained from the literature.*

CO_2 Capture (amine)[3], [4]	$CAPEX\ (million\ \$) = 233.92 \times \left(\frac{t_{CO_2}/day}{5391.09}\right)^{0.61}$
CO_2 Capture (amine) electricity consumption[3], [4]	$0.064\,\frac{kW}{kg\ CO_2/hr}$
CO_2 Drying and Compression[3], [4]	$CAPEX\ (million\ \$) = 30.38 \times \left(\frac{t_{CO_2}/day}{4848.94}\right)^{0.77}$
CO_2 Drying and Compression electricity consumption[3], [4]	$0.073\,\frac{kW}{kg\ CO_2/hr}$
Hydrogen liquefaction[6]	$CAPEX\ (million\ \$) = 7.23 \times \left(t_{H_2}/day\right)^{0.8}$
Hydrogen liquefaction electricity consumption[6]	$8.763\,\frac{kW}{kg\ H_2/hr}$
Liquid hydrogen on-site storage for 1 day [5]	$CAPEX\ (million\ \$) = 7.359 \times \left(\frac{t_{H_2}/day}{108864}\right)^{0.7}$

- Weighted average cost of municipal solid waste: $0 per bone dry ton
- Liquid fuels current wholesale price: $2.35 per gallon gasoline equivalent
- Compressed hydrogen current wholesale price: $2.00 per kg
- Liquid hydrogen current wholesale price: $2.90 per kg
- Natural gas current wholesale price: $4.16 per thousand cubic feet
- Electricity current wholesale price: $0.06 per kilowatt hour

In Table S7, we show example calculations for the various technology options available for processing forest biomass into different products. These calculations are performed for a single facility of the listed size – to scale to the total amount of biomass available, multiple facilities will need to be built. The capital cost of the reference conversion pathway is shown alongside the capital costs for the additional equipment added on using the equations shown above in Table S6.

Equation S1. *Annual cost calculation used in deriving the cost to capture* CO_2

$$Total\ Annualized\ OPEX = CAPEX \times CCF + \ Fixed\ OPEX + Variable\ OPEX$$

Equation S2. *Calculation used in deriving the cost to capture CO2*

$$Cost\ to\ Capture\ CO_2 = \frac{Total\ Annualized\ OPEX - Product\ Revenue}{Negative\ Emissions\ Potential}$$

Table S7. *Example calculations for the cost to process forest biomass and generate negative emissions on a single-facility basis.*

Technology	Gasification			Combustion	Fast Pyrolysis		
Product	**Liquid Fuels**	**Liquid Hydrogen**	**Electricity**	**Electricity**	**Liquid Fuels**	**Liquid Hydrogen**	**Electricity**
Reference process	**[7]**	**[7]**	**[8]**	**[8]**	**[9]**	**[10]**	**[11]**
Biomass throughput (bdt/day)	4536	4536	4536	4536	2000	2000	329
Captured CO_2 (ton CO_2/ton biomass)	1.25	1.65	1.55	1.55	0.49	1.49	1.59
Negative emissions potential (million tons CO_2/year)	1.87	2.46	2.31	2.31	0.32	0.98	0.17
Product rate (1,000,000/year)	72 GGE	125 kg	3173 kWh	2014 kWh	56 GGE	61 kg	133 kWh
Capital expenditure (CAPEX)							
Conversion process (million $)	1,119	893	949	384	275	237	26.5
CO_2 capture, compression and storage (million $)	135	72.1	568	568	86.9	168	60.0
Hydrogen liquefaction and storage (million $)	n/a	728	n/a	n/a	n/a	423	n/a
Total CAPEX (million $)	1,254	1,692	1,517	952	362	828	87
Operating expenditure (OPEX)							
Capital charge (million $/year)	188	254	228	143	54.3	124	13.0
Fixed OPEX (million $/year)	56.4	76.2	68.3	42.8	16.3	37.3	3.9
Feedstock cost (million $/year)	59.6	59.6	59.6	59.6	26.3	26.3	4.3
Other variable OPEX (million $/year)	7.4	66.5	9.1	9.1	37.0	28.9	0.1
Total annualized OPEX (million $/year)	312	456	365	254	134	217	21.3
Product revenue (million $/year)	169	361	190	121	131	177	8.0
Net cost of process (million $/year)	142	95.1	174	134	2.6	39.5	13.3
Cost to capture CO_2 ($/ton CO_2)	76	39	75	58	8	40	78

Appendix E: Biogas Utilization Cost Calculations

Table S8 – Biogas compositions used in this report.

Source	Biogas Production Step	Biogas Composition
Wastewater	Anaerobic Digestion	65% CH_4 35% CO_2
Dairy Manure	Anaerobic Digestion	60% CH_4 40% CO_2
Food Waste	Anaerobic Digestion	60% CH_4 40% CO_2
Landfill Gas	None	50% CH_4 50% CO_2

Table S9 summarizes the basis of the cost estimates. Each cost has up to seven components, which are summed to give the total cost. Later, the economically viable facilities are selected from the complete set for each scenario and the CO_2 quantities and weighted-average costs from this subset are reported for each scenario. The components of the cost estimates are described in more detail below.

Using the capital and operating expenses reported in the EPA report [12] for four different plant sizes, we fitted the following cost function, as shown in Figure S1:

Table S9. *Summary of basis for biogas scenario cost estimates. "Local CC" refers to CO_2 capture at the biogas facility. "RNG" is Renewable Natural Gas: biogas that is purified to natural gas standards. Aggregation pipeline is the low-pressure, fiberglass pipeline that aggregates raw biogas from manure facilties. Gathering pipeline is the high pressure pipeline for purified biomethane that connects the biogas facility to the natural gas network.*

Cost Component	Onsite RNG Use	Pipeline RNG	Power plant – new build	Power plant – retrofit	Power plant – new build and local CC	Power plant – retrofit and local CC
Upgrading and methane compression	Eqn S3	Eqn S3	Eqn S3	Eqn S3	Eqn S3	Eqn S3
Local CO_2 compression	Eqn S4	Eqn S4	–	–	Eqn S4	Eqn S4
Local CO_2 storage	Eqn S5	Eqn S5	–	–	Eqn S5	Eqn S5
Aggregation pipeline	\$0.2M/mi and 1 mi per manure facility	\$0.2M/mi and 1 mi per manure facility	\$0.2M/mi and 1 mi per manure facility	\$0.2M/mi and 1 mi per manure facility	\$0.2M/mi and 1 mi per manure facility	\$0.2M/mi and 1 mi per manure facility
Gathering pipeline	--	\$1M/mi and distance by facility	\$1M/mi and distance by facility	\$1M/mi and distance by facility	\$1M/mi and distance by facility	\$1M/mi and distance by facility
CO_2 capture at power plant	--	--	\$120/ton CO_2	\$87/ton CO_2	\$120/ton CO_2	\$87/ton CO_2
Revenue	\$210/ton CH_4 (\$4/million Btu)	\$210/ton CH_4 (\$4/million Btu)	\$0.06/kWh electricity	\$0.06/kWh electricity	\$0.06/kWh electricity	\$0.06/kWh electricity

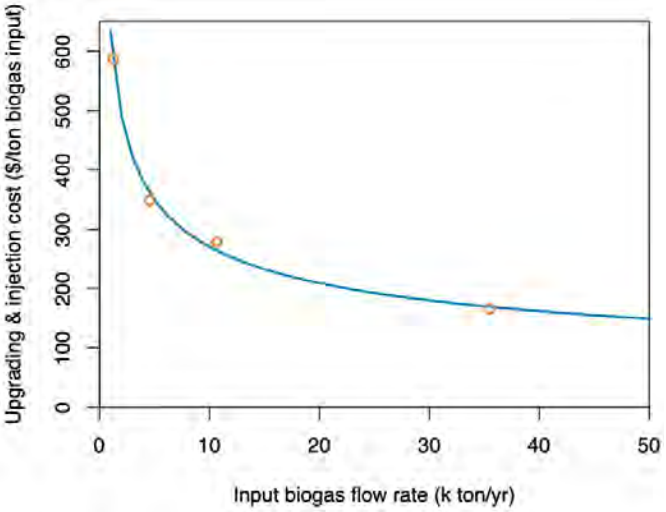

Figure S1. *Fitted cost function for biogas upgrading, including biomethane separation, compression and pipeline injection. Red points represent cases from EPA, 2016. Blue curve shows best fit line represented by Equation S 3. Cost includes methane compression and pipeline injection. On the x-axis, k ton/yr signifies kilotons/year.*

Equation S3. *Fitted cost function for biogas upgrading.*

$$\text{Cost} = 8163 \times Flowrate^{-0.370}$$

Here, Cost is in $/ton biogas input and Flowrate is in ton/yr biogas input. EPA also calculates levelized costs for their scenarios, giving values of $7.51—$23.5 per million Btu output. Our equivalent costs are 18—35% higher on an energy basis because we use a 15% capital charge rate, which is a much higher effective discount rate than the 6% interest and 20-year plant life assumed by EPA. These costs include compression of the methane and an injection station to join the biomethane to the natural gas distribution network, which together make up about a quarter of the capital cost.

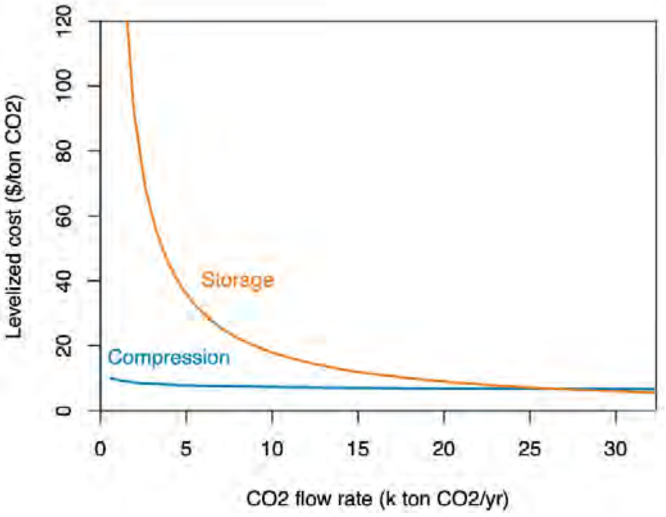

Figure S2. *Cost functions for CO_2 compression and temporary storage at biogas facilities. Curves represent equations S4 and S5.*

Local CO_2 compression and temporary storage

For scenarios where CO_2 is captured from the biogas upgrading system, the CO_2 must be compressed and stored onsite for pickup by a tanker truck. Depending on the size of facility, the flowrate amounts to less than one to up to about four trucks per day of CO_2. As will be shown in Chapter 7, these flowrates are unlikely to justify CO_2 pipeline or rail construction, but transport by truck is reasonable. The cost of compression is adapted from Zoelle et al. [4] using the following equation:

Equation S4. *Cost of CO2 compression for biogas facilities.*

$$Cost = 24.7 \times Flowrate^{-0.25} + 4.38$$

where Cost is in $/ton CO_2 and Flowrate is in ton CO_2/yr. The result is shown in Figure S2. The cost of a storage tank is estimated to be $1.2 million (installed cost with auxiliary equipment), as described in Chapter 7. This is for a 30-ton capacity tank, which is a bit larger than a truckload (20—25 ton CO_2). The tank cost is levelized according to:

Equation S5. *Levelized capital cost equation.*

$$Cost = \frac{Capital\ cost \times Capital\ charge\ rate}{Flowrate}$$

where the capital charge rate is 15%/yr and Flowrate is in ton CO_2/yr. These results are also shown in Figure S2.

Pipelines

Aggregation pipelines apply only to manure facilities and they connect the facility to a central processing point. In our model, the number of dairies served by a central site ranges from 23 for each of Kern County's two upgrading facilities, to 112 for San Joaquin County's single upgrading facility. Since the dairies tend to be regionally clustered and can be daisy-chained by the low-pressure fiberglass pipeline, we assume one mile of pipeline per dairy, giving 23—112 miles of pipeline per upgrading facility. We assume the installed cost of the low pressure pipeline is $0.2 million per mile, [13] which is levelized according to Equation S5.

Gathering pipelines are traditional natural gas pipelines that are built to connect the upgrading facilities to the existing natural gas network. These pipelines are assumed to cost

$1 million per mile [14], [13] which is on the high side of available estimates due to concerns about higher-than-average costs of construction in California. The length of gathering pipeline for each upgrading facility is estimated using ArcGIS as the straight-line distance between the facility and the nearest existing major pipeline. The distance for manure upgrading facilities is taken to be the average of the distances for constituent dairies. The resulting distribution of distances is shown in Figure S3. Most facilities are within five miles of a pipeline.

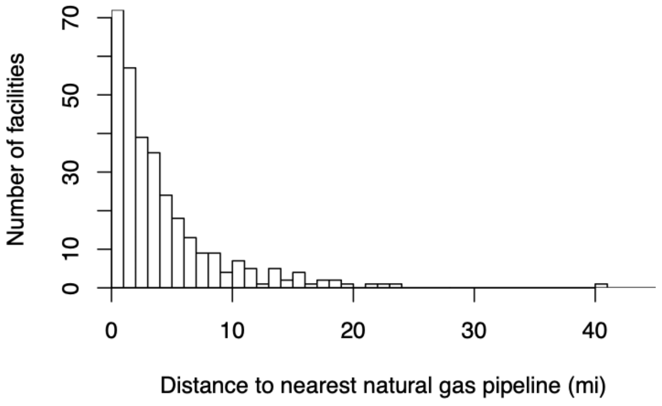

Figure S3. *Distribution of calculated distances of biogas upgrading facilities to the nearest major natural gas pipeline.*

Table S10. *Parameters for biogas power plant cost calculation. COE is the levelized Cost of Electricity.*

Scenario	3 (new build)	4 (retrofit)
Case number in NETL report[4]	B31B	Mean of 1c, 2c, 3c
COE ($/MWh), capital	26.9	16
COE ($/MWh), fixed	6.6	6.7
COE ($/MWh), variable	4.0	3.5
COE ($/MWh), fuel	45.9	45
Plant Heat Rate (Btu/kWh)	7466	7296
Electricity Revenue ($/MWh)	60	60
Total COE excluding fuel (2011$/MWh)	37.5	26
Total COE excluding fuel (2018$/MWh)	42	30
Normalized Capture Rate (ton CO_2/MWh)	0.35	0.34
Normalized Cost ($/ton CO_2 captured)	120	86
Normalized Revenue ($/ton CO_2 captured)	171	175

Appendix F: 2025 Cost Curves

The amounts of negative emissions, and the cost to achieve those emissions, are somewhat different in 2025 compared to those in 2045. In particular, the amount of negative emissions achievable by natural solutions is much lower in 2025 than in 2045, leading to a larger amount of conventional direct air capture that is necessary to achieve 125 million tons of CO_2 per year. Additionally, small changes in the biomass availability between the two analysis years vary the amount of CO_2 that can be captured via the treatment technologies.

The costs to achieve negative emissions are also changed based on the time considered. We applied technology learning onto direct air capture and fast pyrolysis, but the benefits of learning are only realized due to accumulated deployment of the technologies. Therefore, learning was only applied to the capital costs considered for 2045; the costs in 2025 are higher because learning was not applied. This has the consequence of making geothermal direct air capture more expensive than conventional direct air capture, due to the construction of new geothermal wells. We assume that based on forecasted technology learning, which suggests that geothermal direct air capture will experience faster learning than conventional direct air capture leading to lower cost in 2045, geothermal direct air capture will be pursued in 2025, despite the initially higher cost.

Lastly, the avoided fossil emissions for electricity different between the two years; in 2045, electricity is mandated to be zero-carbon, and so we assume there will be no fossil-derived electricity emissions to avoid. However, there will still be some fossil-derived electricity in the electrical grid in 2025; therefore, there are associated avoided fossil emissions.

The cost curves for 2025 can be found in this appendix, Figure S4 to Figure S9.

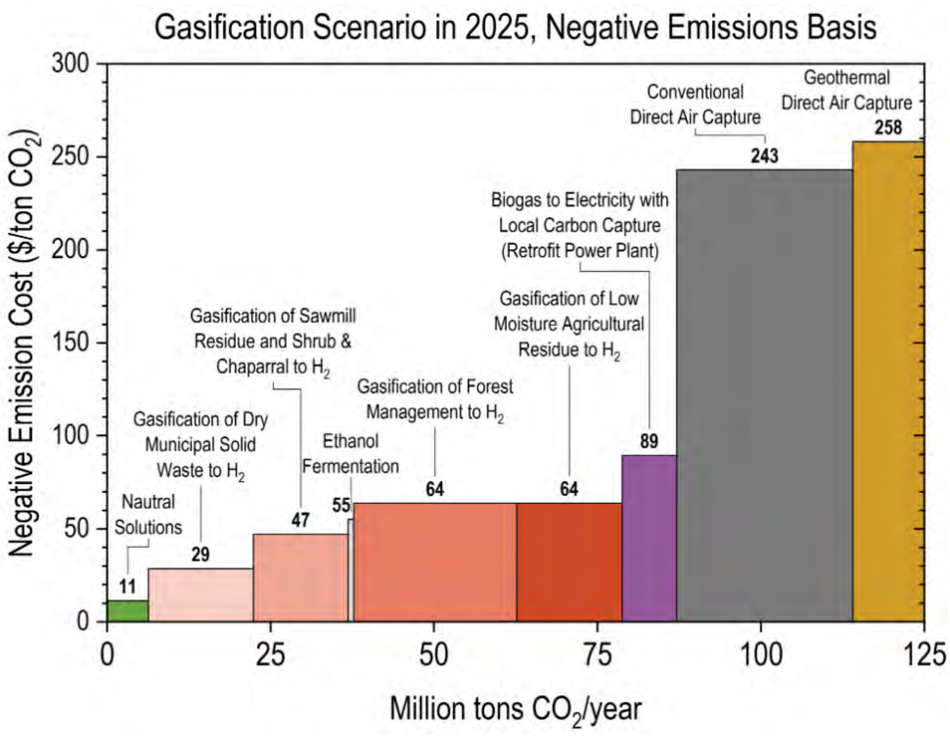

Figure S4. *Total cost curve for Gasification Scenario, 2025, negative emissions basis. The total (integrated) system cost for this scenario is 14.0 billion $ per year.*

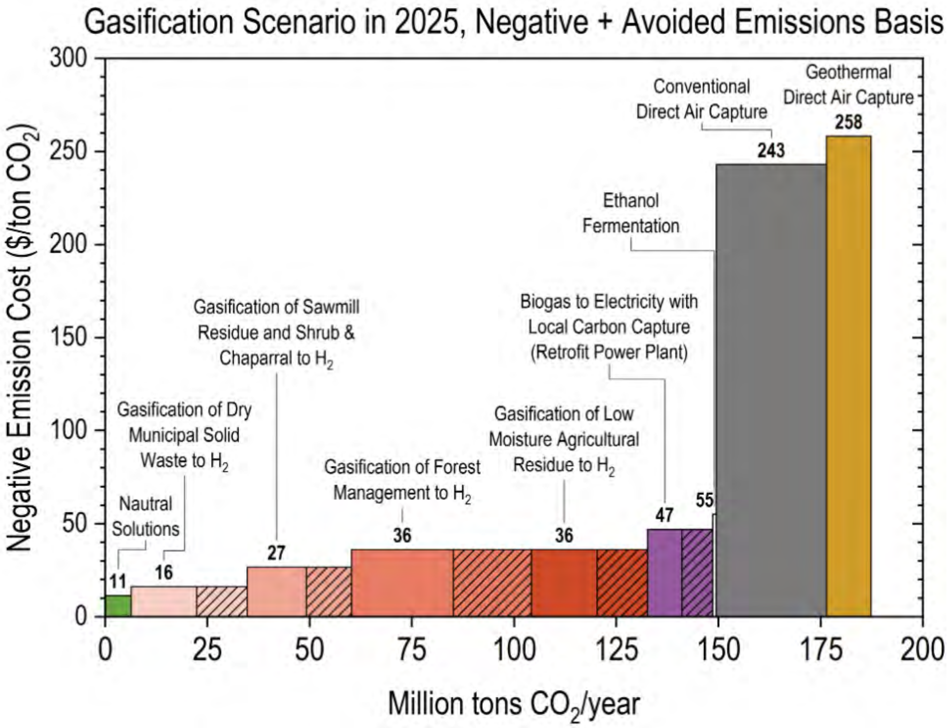

Figure S5. *Total cost curve for Gasification Scenario, 2025, negative and avoided emissions basis. Hatched areas represent avoided emissions. The total (integrated) system cost for this scenario is 14.0 billion $ per year.*

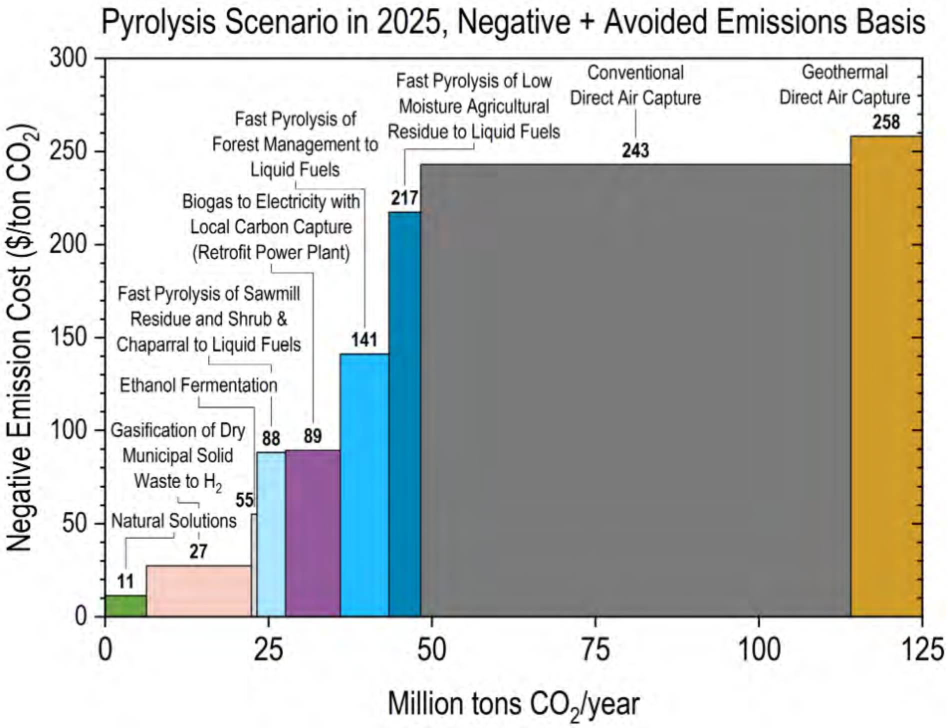

Figure S6. *Total cost curve for Pyrolysis Scenario, 2025, negative emissions basis. The total (integrated) system cost for this scenario is 22.6 billion $ per year.*

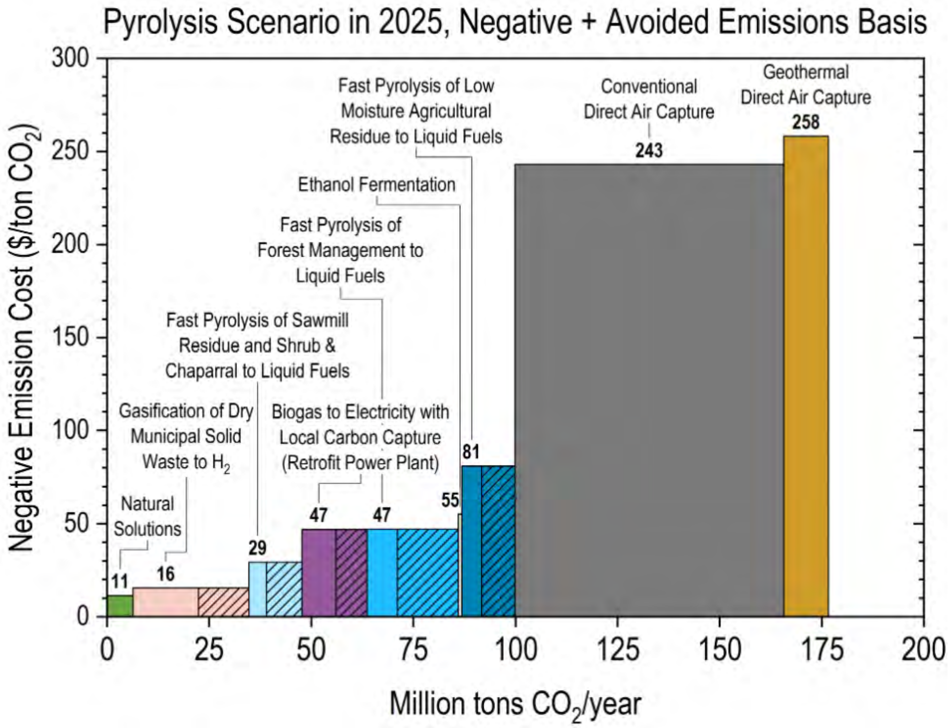

Figure S7. *Total cost curve for Pyrolysis Scenario, 2025, negative and avoided emissions basis. Hatched areas represent avoided emissions. The total (integrated) system cost for this scenario is 22.6 billion $ per year.*

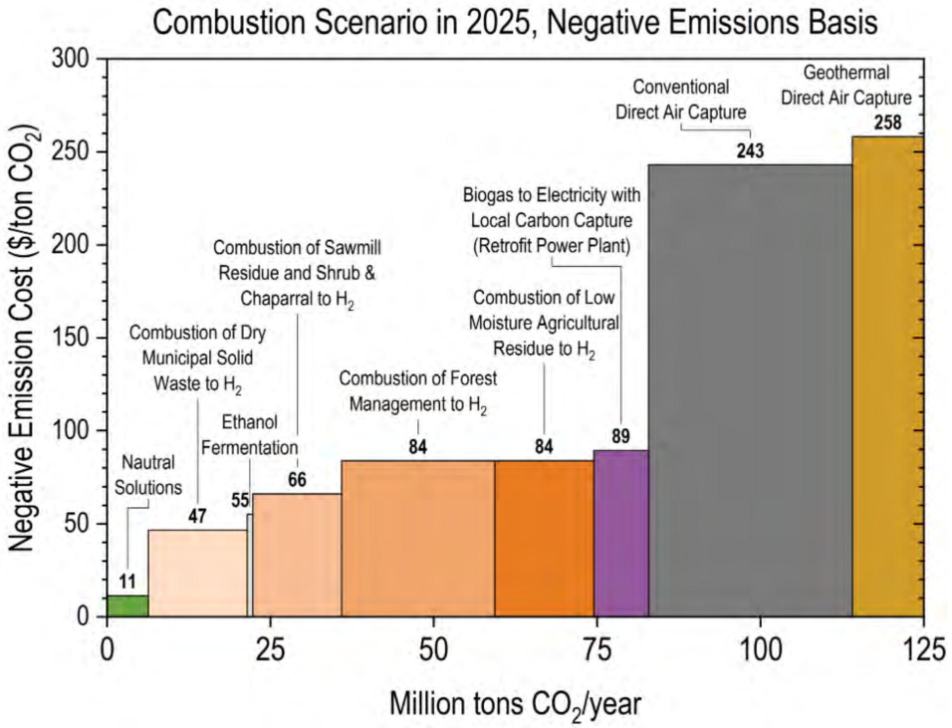

Figure S8. *Total cost curve for Combustion Scenario, 2025, negative emissions basis. The total (integrated) system cost for this scenario is 16.1 billion $ per year.*

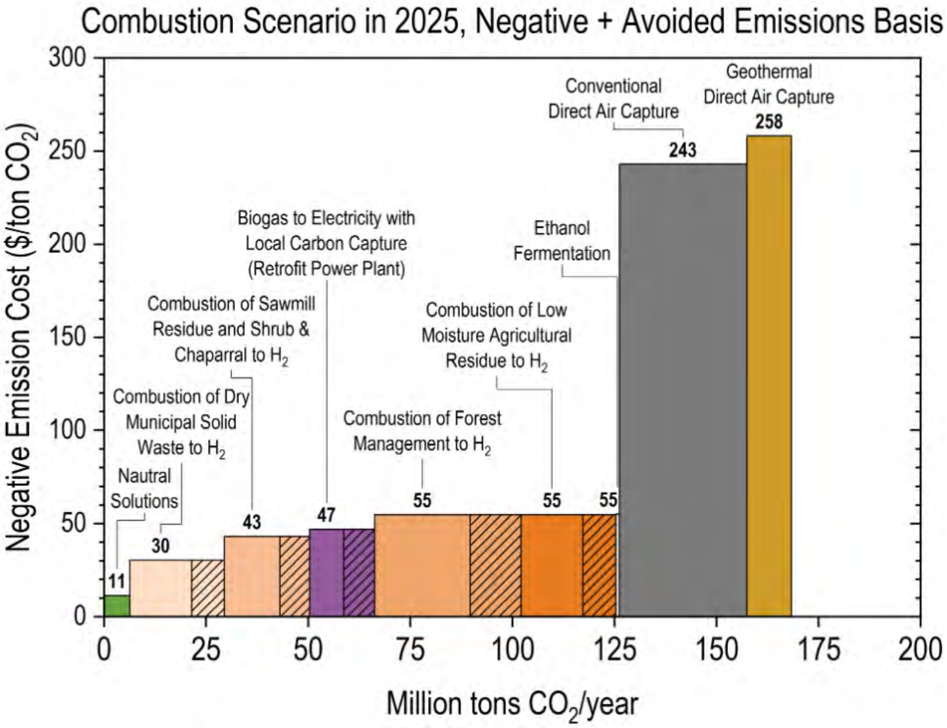

Figure S9. *Total cost curve for Combustion Scenario, 2025, negative and avoided emissions basis. Hatched areas represent avoided emissions. The total (integrated) system cost for this scenario is 16.1 billion $ per year.*

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