Fuel chain carbon lock-in potential of crudeto-biofuel petroleum refinery repurposing

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ABSTRACT

Moves to deoxygenate farmed lipids with hydrogen by repurposing troubled crude refining assets for "drop in" biofuels add a new carbon source to the liquid hydrocarbon fuel chain, with the largest biorefineries of this type that the world has ever seen now proposed in California. Characteristics of this particular biofuel technology were assessed across its shared fuel chain with petroleum for path-dependent feedstock acquisition, processing, fuel mix, and energy system effects on the environment at this newly proposed scale. The analysis was grounded by site-specific data in California.

This work found significant potential impacts are foreseeable. Overcommitment to purposegrown biomass imports could shift emissions out of state instead of sequestering carbon. Fossil fuel assets repurposed for hydrogen-intensive deoxygenation could make this type of biorefining more carbon intensive than crude refining, and could worsen refinery fire, explosion, and flaring hazards. Locked into making distillate fuels, this technology would lock in diesel and compete with zero-emission freight and shipping for market share and hydrogen. That path-dependent impact could amplify, as electric cars replace gasoline and idled crude refining assets repurpose for more biomass carbon, to turn the path of energy transition away from climate stabilization. Crucially, this work also found that a structural disruption in the liquid hydrocarbon fuel chain opened a window for another path, to replace the freight and shipping energy function of crude refining without risking these impacts. The type and use of hydrogen production chosen will be pivotal in this choice among paths to different futures.

ACRONYMS AND TERMS

| Barrel (b): | A barrel of oil is a volume of 42 U.S. gallons. |
|-------------------|---|
| BEV: | Battery-electric vehicle. |
| Biofuel: | Hydrocarbons derived from biomass and burned for energy. |
| Biomass: | Any organic material that is available on a recurring basis, excluding fossil fuels. |
| Carbon intensity: | The amount of climate emission caused by a given amount of activity at a particular emission source. Herein, CO ₂ or CO ₂ e mass per barrel refined, or SCF hydrogen produced. |
| Carbon lock-in: | Resistance to change of carbon-emitting systems that is caused by mutually reinforcing technological, capital, institutional, and social commitments to the polluting system which have become entrenched as it was developed and used. A type of path dependance. |
| Catalyst: | A substance that facilitates a chemical reaction without being consumed in the reaction. |
| Ester: | A molecule or functional group derived by condensation of an alcohol and an acid with simultaneous loss of water. Oxygen, carbon, and other elements are bonded together in esters. |
| Electrolysis: | Chemical decomposition produced by passing an electric current through a liquid or solution containing ions. Electrolysis of water produces hydrogen and oxygen. |
| FCEV: | Fuel cell electric vehicle. |
| HDO: | Hydrodeoxygenation. Reactions that occur in HEFA processing. |
| HEFA: | Hydrotreating esters and fatty acids. A biofuel production technology. |
| Hydrocarbon: | A compound of hydrogen and carbon. |
| Lipids: | Organic compounds that are oily to the touch and insoluble in water, such as fatty acids, oils, waxes, sterols, and triacylglycerols (TAGS). Fatty acids derived from TAGs are the lipid-rich feedstock for HEFA biofuel production. |
| MPC: | Marathon Petroleum Corporation, headquartered in Findlay, OH. |
| P66: | Phillips 66 Company, headquartered in Houston, TX. |
| SCF: | Standard cubic foot. 1 ft^3 of gas that is not compressed or chilled. |
| TAG: | Triacylglycerol. Also commonly known as triglyceride. |
| Ton (t): | Metric ton. |
| ZEV: | Zero-emission vehicle. |

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Supporting Material — Separately Bound Appendix¹

FINDINGS AND TAKEAWAYS

Finding 1. Oil companies are moving to repurpose stranded and troubled petroleum assets using technology called "Hydrotreated Esters and Fatty Acids" (HEFA), which converts vegetable oil and animal fat lipids into biofuels that refiners would sell for combustion in diesel engines and jet turbines. The largest HEFA refineries to be proposed or built worldwide to date are now proposed in California.

Takeaways

- F1.1 Prioritizing industry asset protection interests ahead of public interests could lock in HEFA biofuels instead of cleaner alternatives to petroleum diesel and jet fuel.
- F1.2 HEFA refining could continue to expand as refiners repurpose additional crude refining assets that more efficient electric cars will idle by replacing gasoline.
- F1.3 Assessment of potential impacts across the HEFA fuel chain is warranted before locking this new source of carbon into a combustion-based transportation system.
- **Finding 2.** Repurposing refining assets for HEFA biofuels could increase refinery explosion and fire hazards. Switching from near-zero oxygen crude to 11 percent oxygen biomass feeds would create new damage mechanisms and intensify hydrogendriven exothermic reaction hazards that lead to runaway reactions in biorefinery hydro-conversion reactors. These hydrogen-related hazards cause frequent safety incidents and even when safeguards are applied, recurrent catastrophic explosions and fires, during petroleum refining. At least 100 significant flaring incidents traced to these hazards occurred since 2010 among the two refineries where the largest crude-to-biofuel conversions are now proposed. Catastrophic consequences of the new biorefining hazards are foreseeable.

- F2.1 Before considering public approvals of HEFA projects, adequate reviews will need to report site-specific process hazard data, including pre-project and postproject equipment design and operating data specifications and parameters, process hazard analysis, hazards, potential safeguards, and inherent safety measures for each hazard identified.
- F2.2 County and state officials responsible for industrial process safety management and hazard prevention will need to ensure that safety and hazard prevention requirements applied to petroleum refineries apply to converted HEFA refineries.

Finding 3. Flaring by the repurposed biorefineries would result in acute exposures to episodic air pollution in nearby communities. The frequency of these recurrent acute exposures could increase due to the new and intensified process safety hazards inherent in deoxygenating the new biomass feeds. Site-specific data suggest bimonthly acute exposure recurrence rates for flare incidents that exceed established environmental significance thresholds. This flaring would result in prolonged and worsened environmental justice impacts in disparately exposed local communities that are disproportionately Black, Brown, or low-income compared with the average statewide demographics.

Takeaways

- F3.1 Before considering public approvals of HEFA projects, adequate reviews will require complete analyses of potential community-level episodic air pollution exposures and prevention measures. Complete analyses must include worst-case exposure frequency and magnitude with impact demographics, apply results of process hazard, safeguard, and inherent safety measures analysis (F2.1), and identify measures to prevent and eliminate flare incident exposures.
- F3.2 The Bay Area, San Joaquin Valley, and South Coast air quality management districts will need to ensure that flare emission monitoring and flaring prevention requirements applied to petroleum refineries apply to converted HEFA refineries.
- **Finding 4.** Rather than contributing to a reduction in emissions globally, HEFA biofuels expansion in California could actually shift emissions to other states and nations by reducing the availability of limited HEFA biofuels feedstock elsewhere. Proposed HEFA refining for biofuels in California would exceed the per capita state share of total U.S. farm yield for all uses of lipids now tapped for biofuels by 260 percent in 2025. Foreseeable further HEFA growth here could exceed that share by as much as 660 percent in 2050. These impacts are uniquely likely and pronounced for the type of biomass HEFA technology demands.

- F4.1 A cap on in-state use of lipids-derived biofuel feedstocks will be necessary to safeguard against these volume-driven impacts. *See also Takeaway F6.1*.
- F4.2 Before considering public approvals of HEFA projects, adequate reviews will need to fully assess biomass feedstock extraction risks to food security, lowincome families, future global farm yields, forests and other natural carbon sinks, biodiversity, human health, and human rights using a holistic and precautionary approach to serious and irreversible risks.
- F4.3 This volume-driven effect does not implicate the Low Carbon Fuel Standard and can only be addressed effectively via separate policy or investment actions.

Finding 5. Converting crude refineries to HEFA refineries would increase the carbon intensity of hydrocarbon fuels processing to 180–240 percent of the average crude refinery carbon intensity nationwide. Refiners would cause this impact by repurposing otherwise stranded assets that demand more hydrogen to deoxygenate the type of biomass the existing equipment can process, and supply that hydrogen by emitting some ten tons of carbon dioxide per ton of hydrogen produced. In a plausible HEFA growth scenario, cumulative CO₂ emissions from continued use of existing California refinery hydrogen plants alone could reach 300–400 million metric tons through 2050.

Takeaways

- **F5.1** Before considering public approvals of HEFA projects, adequate reviews will need to complete comprehensive biorefinery potential to emit estimates based on site-specific data, including project design specifications, engineering for renewable-powered electrolysis hydrogen capacity at the site, and potential to emit estimates with and without that alternative. *See also Takeaways F7.1–4.*
- **Finding 6.** HEFA biofuels expansion that could be driven by refiner incentives to repurpose otherwise stranded assets is likely to interfere with state climate protection efforts, in the absence of new policy intervention. Proposed HEFA plans would exceed the lipids biofuel caps assumed in state climate pathways through 2045 by 2025. Foreseeable further HEFA biofuels expansion could exceed the maximum liquid hydrocarbon fuels volume that can be burned in state climate pathways, and exceed the state climate target for emissions in 2050.

- **F6.1** A cap on lipids-derived biofuels will be necessary to safeguard against these HEFA fuel volume-driven impacts. *See also Takeaway F4.1.*
- F6.2 Oil company incentives to protect refining and liquid fuel distribution assets suggest HEFA biofuels may become locked-in, rather than transitional, fuels.
- F6.3 A cap on HEFA biofuels would be consistent with the analysis and assumptions in state climate pathways.

Finding 7. A clean hydrogen alternative could prevent emissions, spur the growth of zero-emission fuel cell vehicle alternatives to biofuels, and ease transition impacts. Early deployment of renewable-powered electrolysis hydrogen production at California crude refineries during planned maintenance or HEFA repurposing could prevent 300–400 million metric tons of CO₂ emissions through 2050 and support critically needed early deployment of energy integration measures for achieving zero emission electricity and heavy-duty vehicle fleets.

Moreover, since zero-emission hydrogen production would continue on site for these zero-emission energy needs, this measure would lessen local transition impacts on workers and communities when refineries decommission.

- F7.1 This feasible measure would convert 99 percent of current statewide hydrogen production from carbon-intensive steam reforming to zero-emission electrolysis. This clean hydrogen, when used for renewable grid balancing and fuel cell electric vehicles, would reap efficiency savings across the energy system.
- F7.2 Early deployment of the alternatives this measure could support is crucial during the window of opportunity to break free from carbon lock-in which opened with the beginning of petroleum asset stranding in California last year and could close if refiner plans to repurpose those assets re-entrench liquid combustion fuels.
- F7.3 During the crucial early deployment period, when fuel cell trucks and renewable energy storage could be locked out from use of this zero-emission hydrogen by excessive HEFA growth, coupling this electrolysis measure with a HEFA biofuel cap (*F4.1; F6.1*) would greatly increase its effectiveness.
- F7.4 Coupling the electrolysis and HEFA cap measures also reduces HEFA refinery hazard, localized episodic air pollution and environmental justice impacts.
- F7.5 The hydrogen roadmap in state climate pathways includes converting refineries to renewable hydrogen, and this measure would accelerate the deployment timeline for converting refinery steam reforming to electrolysis hydrogen production.

INTRODUCTION

i.1 Biofuels in energy systems

Fossil fuels redefined the human energy system. Before electric lights, before gaslights, whale oil fueled our lanterns. Long before whaling, burning wood for light and heat had been standard practice for millennia. Early humans would learn which woods burned longer, which burned smokier, which were best for light, and which for heat. Since the first fires, we have collectively decided on which biofuel carbon to burn, and how much of it to use, for energy.

We are, once again, at such a collective decision point. Biofuels—hydrocarbons derived from biomass and burned for energy—seem, on the surface, an attractive alternative to crude oil. However, there are different types of biofuels and ways to derive them, each carrying with it different environmental impacts and implications. Burning the right type of biofuel for the right use *instead* of fossil fuels, such as cellulose residue-derived instead of petroleum-derived diesel for old trucks until new zero emission hydrogen-fueled trucks replace them, might help to avoid severe climate and energy transition impacts. However, using more biofuel burns more carbon. Burning the wrong biofuel *along with* fossil fuels can increase emissions—and further entrench combustion fuel infrastructure that otherwise would be replaced with cleaner alternatives.

i.1.1 Some different types of biofuel technologies

Corn ethanol

Starch milled from corn is fermented to produce an alcohol that is blended into gasoline. Ethanol is about 10% of the reformulated gasoline sold and burned in California.

Fischer-Tropsch synthesis

This technology condenses a gasified mixture of carbon monoxide and hydrogen to form hydrocarbons and water, and can produce synthetic biogas, gasoline, jet fuel, or diesel biofuels. A wide range of materials can be gasified for this technology. Fischer-Tropsch synthesis can make any or all of these biofuels from cellulosic biomass such as cornstalk or sawmill residues.

Biofuel in the Climate System 101

People and other animals exhale carbon dioxide into the air while plants take carbon dioxide out of the air. Biofuel piggybacks on—and alters—this natural carbon cycle. It is fuel made to be burned but made from plants or animals that ate plants. Biofuels promise to let us keep burning fuels for energy by putting the carbon that emits back into the plants we will make into the fuels we will burn next year. All we have to do is grow a lot of extra plants, and keep growing them.

But can the biofuel industry keep that promise?

This much is clear: burning biofuels emits carbon and other harmful pollutants from the refinery stack and the tailpipe. Less clear is how many extra plants we can grow; how much land for food, natural ecosystems and the carbon sinks they provide it could take; and ultimately, how much fuel combustion emissions the Earth can take back out of the air.

Some types of biofuels emit more carbon than the petroleum fuels they replace, raise food prices, displace indigenous peoples, and worsen deforestation. Other types of biofuels might help, along with more efficient and cleaner renewable energy and energy conservation, to solve our climate crisis.

How much of which types of biofuels we choose matters.

"Biodiesel"

Oxygen-laden hydrocarbons made from lipids that can only be burned along with petroleum diesel is called "biodiesel" to denote that limitation, which does not apply to all diesel biofuels.

Hydrotreating esters and fatty acids (HEFA)

HEFA technology produces hydrocarbon fuels from lipids. This is the technology crude refiners propose to use for biofuels. The diesel hydrocarbons it produces are different from "biodiesel" and are made differently, as summarized directly below.

i.2 What is HEFA technology?

i.2.1 How HEFA works

HEFA removes oxygen from lipidic (oily) biomass and reformulates the hydrocarbons this produces so that they will burn like certain petroleum fuels. Some of the steps in HEFA refining are similar to those in traditional petroleum refining, but the "deoxygenation" step is very different, and that is because lipids biomass is different from crude and its derivatives.

i.2.2 HEFA feedstocks

Feedstocks are detailed in Chapter 2. Generally, all types of biomass feedstocks that HEFA technology can use contain lipids, which contain oxygen, and nearly all of them used for HEFA biofuel today come directly or indirectly from one (or two) types of farming.

Purpose-grown crops

Vegetable oils from oil crops, such as soybeans, canola, corn, oil palm, and others, are used directly and indirectly as HEFA feedstock. Direct use of crop oils, especially soy, is the major

portion of total HEFA feeds. Indirect uses are explained below. Importantly, these crops were cultivated for food and other purposes which HEFA biofuels now compete with—and a new oil crop that has no existing use can still compete for farmland to grow it. Some other biofuels, such as those which can use cellulosic residues as feedstock for example, do not raise the same issue. Thus, in biofuels jargon, the term "purpose-grown crops" denotes this difference among biofuels.

Animal fats

Rendered livestock fats such as beef tallow, pork lard, and chicken fat are the second largest portion of the lipids in HEFA feedstock, although that might change in the future if refiners tap fish oils in much larger amounts. These existing lipid sources also have existing uses for food and other needs, many of which are interchangeable among the vegetable and animal lipids. Also, particularly in the U.S. and similar agricultural economies, the use of soy, corn and other crops as livestock feeds make purpose-grown crops the original source of these HEFA feeds.

Used cooking oils

Used cooking oil (UCO), also called yellow grease or "waste" oil, is a variable mixture of used plant oils and animal fats, typically collected from restaurants and industrial kitchens. It notably could include palm oil imported and cooked by those industries. HEFA feeds include UCO, though its supply is much smaller than those of crop oils or livestock fats. UCO, however, originates from the same purpose grown oil crops and livestock, and UCO has other uses, many of which are interchangeable with the other lipids, so it is not truly a "waste" oil.

i.2.3 HEFA processing chemistry

The HEFA process reacts lipids biomass feedstock with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. The intended reactions of this "hydro-conversion" accomplish the deoxygenation and reformulation steps noted above.

The role of hydrogen in HEFA production

Hydrogen is consumed in several HEFA process reactions, especially deoxygenation, which removes oxygen from the HEFA process hydrocarbons by bonding with hydrogen to form water. Hydrogen also is essential for HEFA process reaction control. As a result, HEFA processing requires vast amounts of hydrogen, which HEFA refineries must produce in vast amounts. HEFA hydro-conversion and hydrogen reaction chemistry are detailed in Chapter 1.

i.2.4 What HEFA produces

"Drop in" diesel

One major end product of HEFA processing is a "drop-in" diesel that can be directly substituted for petroleum diesel as some, or all, of the diesel blend fueled and burned. Drop-in diesel is distinct from biodiesel, which must be blended with petroleum diesel to function in combustion engines and generally needs to be stored and transported separately. Drop-in diesel

is also referred to as "renewable" diesel, however, those labels also apply to diesel made by other biofuel technologies, so diesel produced by the HEFA process is called "HEFA diesel" herein.

"Sustainable Aviation Fuel"

The other major end product of HEFA processing is a partial substitute for petroleum-based jet fuel, sometimes referred to as "Sustainable Aviation Fuel" or "SAF," which also is produced by other biofuel technologies. HEFA jet fuel is allowed by aviation standards to be up to a maximum of 50% of the jet fuel burned, so it must be blended with petroleum jet fuel.

i.3 Conversions of Crude oil refineries to HEFA

i.3.1 Current and proposed conversions of oil refineries

Phillips 66 Co. (P66) proposes to convert its petroleum refinery in Rodeo, CA into a 80,000 barrel per day (b/d) biorefinery.² In nearby Martinez, Marathon Petroleum Corporation (MPC) proposes a 48,000 b/d biorefinery³ at the site where it closed a crude refinery in April 2020.⁴ Other crude-to-biofuel refinery conversions are proposed or being built in Paramount, CA (21,500 b/d new capacity),⁵ Bakersfield, CA (15,000 b/d),⁶ Port Arthur, TX (30,700 b/d),⁷ Norco, LA (17,900 b/d new capacity),⁸ and elsewhere. All of these projects are super-sized compared with the 2,000–6,000 b/d projects studied as of just a few years ago.⁹ The P66 Rodeo and MPC Martinez projects are the largest of their kind to be proposed or built to date. P66 boasts that its Rodeo biorefinery would be the largest in the world.¹⁰

i.3.2 <u>Repurposing of existing equipment</u>

Remarkably, all of the crude-to-biofuel conversion projects listed above seek to use HEFA technology—none of the refiners chose Fischer-Tropsch synthesis despite its greater flexibility than HEFA technology and ability to avoid purpose-grown biomass feedstock. However, this is consistent with repurposing the plants already built. The California refiners propose to repurpose existing hydro-conversion reactors—hydrocrackers or hydrotreaters—for HEFA processing, and existing hydrogen plants to supply HEFA process hydrogen needs.^{2–6} Moreover, it is consistent with protecting otherwise stranded assets; repurposed P66 and MPC assets have recently been shut down, are being shut down, or will potentially be unusable soon, as described in Chapter 1.

While understandable, this reaction to present and impending petroleum asset stranding appears to be driving our energy system toward HEFA technology instead of potentially cleaner alternatives at an enormous scale, totaling 164,500 b/d by 2024 as proposed now in California. This assets protection reaction also presents a clear potential for further HEFA expansion. Refiners could continue to repurpose petroleum refining assets which will be idled as by the replacement of gasoline with more efficient electric passenger vehicles.

Before allowing this new source of carbon to become locked into a future combustion-based transportation system, assessment of potential impacts across the HEFA fuel chain is warranted.

i.4 Key questions and concerns about crude-to-biofuel conversions

i.4.1 Potential impacts of biomass feedstock acquisition

Proposed and potential HEFA expansions in California would rapidly and substantially increase total demand for globally traded agricultural lipids production. This could worsen food insecurity, risk deforestation, biodiversity and natural carbon sink impacts from expansions of farm and pasture lands, and drive populations elsewhere to prioritize use of their remaining lipids shares for food. Biofuel, biodiversity, and climate analysts often refer to the food security impact and agriculture expansion risks in terms of food price and "indirect land use" impacts. The latter effect, on *where* a globally limited biofuel resource could be used, is often referred to by climate policy analysts as an emission-shifting or "leakage" impact. Chapter 2 reviews these potential feedstock acquisition impacts and risks.

i.4.2 Potential impacts of HEFA refinery processing

Processing a different oil feedstock is known to affect refinery hazards and emissions, and converted HEFA refineries would process a very different type of oil feedstock. The carbon intensity—emissions per barrel processed—of refining could increase because processing high-oxygen plant oils and animal fats would consume more hydrogen, and the steam reformers that refiners plan to repurpose emit some ten tons of CO₂ per ton of hydrogen produced. Explosion and fire risks could increase because byproducts of refining the new feeds pose new equipment damage hazards, and the extra hydrogen reacted with HEFA feeds would increase the frequency and magnitude of dangerous runaway reactions in high-pressure HEFA reactors. Episodic air pollution incidents could recur more frequently because refiners would partially mitigate the impacts of those hazards by rapid depressurization of HEFA reactor contents to refinery flares, resulting in acute air pollutant exposures locally. Chapter 3 assesses these potential impacts.

i.4.3 Potential impacts on climate protection pathways

A climate pathway is a road map for an array of decarbonization technologies and measures to be deployed over time. California has developed a range of potential pathways to achieve its climate goals—all of which rely on replacing most uses of petroleum with zero-emission batteryelectric vehicles and fuel cell-electric vehicles (FCEVs) energized by renewable electricity. Proposed and potential HEFA biofuels growth could exceed this range of state pathways or interfere with them in several ways that raise serious questions for our future climate.

HEFA biofuels could further expand as refiners repurpose assets idled by the replacement of gasoline with electric vehicles. This could exceed HEFA caps *and* total liquid fuels volumes in the state climate pathways. Hydrogen committed to HEFA growth would not be available for FCEVs and grid-balancing energy storage, potentially slowing zero-emission fuels growth. High-carbon hydrogen repurposed for HEFA refining, which could not pivot to zero-emission FCEV fueling or energy storage, could lock in HEFA biofuels instead of supporting transitions to cleaner fuels. These critical-path climate factors are assessed in Chapter 4.

i.4.4 Alternatives, opportunities and choices

Zero emission hydrogen alternative

Renewable-powered electrolysis of water produces zero-emission hydrogen that could replace existing high-carbon hydrogen production during refinery maintenance shutdowns and HEFA conversions. Indeed, a "Hydrogen Roadmap" in state climate pathways envisions converting all refineries to renewable hydrogen. This measure could cut emissions, support the growth of FCEVs and grid-balancing energy needed to further expand renewable electricity and zero-emission fuels, and reduce local transition impacts when refineries decommission.

Window of opportunity

A crucial window of opportunity to break out of carbon lock-in has opened with the beginning of California petroleum asset stranding in 2020 and could close if refiner plans to repurpose those assets re-entrench liquid combustion fuels. The opening of this time-sensitive window underscores the urgency of early deployment for FCEV, energy storage, and zero-emission fuels which renewable-powered electrolysis could support.

Potential synergies with HEFA biofuels cap

Coupling this measure with a HEFA biofuels cap has the potential to enhance its benefits for FCEV and cleaner fuels deployment by limiting the potential for electrolysis hydrogen to instead be committed to HEFA refining during the crucial early deployment period, and has the potential to reduce HEFA refining hazard, episodic air pollution and environmental justice impacts.

i.4.5 <u>A refinery project disclosure question</u>

Readers should note that P66² and MPC¹¹ excluded flares and hydrogen production which would be included in their proposed HEFA projects from emission reviews they assert in support of their air permit applications. To date neither refiner has disclosed whether or not its publicly asserted project emission estimate excludes any flare or hydrogen production plant emissions. However, as shown in Chapter 3, excluding flare emissions, hydrogen production emissions, or both could underestimate project emission impacts significantly.

i.5 The scope and focus of this report

This report addresses the questions and concerns introduced above. Its scope is limited to potential fuel chain and energy system impacts of HEFA technology crude-to-biofuel conversion projects. It focuses on the California setting and, within this setting, the Phillips 66 Co. (P66) Rodeo and Marathon Petroleum Corp. (MPC) Martinez projects. Details of the data and methods supporting original estimates herein are given in a Supporting Material Appendix.¹

1. OVERVIEW OF HEFA BIOFUEL TECHNOLOGY

All of the full-scale conversions from petroleum refining to biofuel refining proposed or being built in California now seek to use the same type of technology for converting biomass feedstock into fuels: hydrotreating esters and fatty acids (HEFA).²³⁴⁶ "Hydrotreating" signifies a hydro-conversion process: the HEFA process reacts biomass with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. "Esters and fatty acids" are the type of biomass this hydro-conversion can process: triacylglycerols (TAGs) and the fatty acids derived from TAGs. HEFA feedstock is biomass from the TAGs and fatty acids in plant oils, animal fats, fish oils, used cooking oils, or combinations of these biomass lipids.

This chapter addresses how HEFA biofuel technology functions, which is helpful to assessing its potential impacts in the succeeding chapters, and explores why former and current crude oil refiners choose this technology instead of another available fuels production option.

1.1 HEFA process chemistry

Hydrocarbons formed in this process reflect the length of carbon chains in its feed. Carbon chain lengths of the fatty acids in the TAGs vary by feed source, but in oil crop and livestock fat feeds are predominantly in the range of 14–18 carbons (C14–C18) with the vast majority in the C16–C18 range.¹ Diesel is predominantly a C15–C18 fuel; Jet fuel C8–C16. The fuels HEFA can produce in relevant quantity are thus diesel and jet fuels, with more diesel produced unless more intensive hydrocracking is chosen intentionally to target jet fuel production.

HEFA process reaction chemistry is complex, and in practice involves hard-to-control process conditions and unwanted side-reactions, but its intended reactions proceed roughly in sequence to convert TAGs into distillate and jet fuel hydrocarbons.^{12 13 14 15 16 17 18 19 20 21 22} Molecular sites of these reactions in the first step of HEFA processing, hydrodeoxygenation (HDO), are illustrated in Diagram 1 below.



Fatty acids are "saturated" by bonding hydrogen to their carbon atoms. <u>See</u> (a) in Diagram. This tends to start first. Then, the fatty acids are broken free from the three-carbon "propane knuckle" of the TAG (Diagram 1, left) by breaking its bonds to them via hydrogen insertion. (Depropanation; <u>see</u> (b) in Diagram 1.) Still more hydrogen bonds with the oxygen atoms (c), to form water (H₂O), which is removed from the hydrocarbon process stream. These reactions yield water, propane, some unwanted but unavoidable byproducts (not shown in the diagram for simplicity), and the desired HDO reaction products—hydrocarbons which can be made into diesel and jet fuel.

But those hydrocarbons are not yet diesel or jet fuel. Their long, straight chains of saturated carbon make them too waxy. Fueling trucks or jets with wax is risky, and prohibited by fuel specifications. To de-wax them, those straight-chain hydrocarbons are turned into their branched-chain isomers.

Imagine that the second-to-last carbon on the right of the top carbon chain in Diagram 1 takes both hydrogens bonded to it, and moves to in between the carbon immediately to its left and one of the hydrogens that carbon already is bonded to. Now imagine the carbon at the end of the chain moves over to where the second-to-last carbon used to be, and thus stays attached to the carbon chain. That makes the straight chain into its branched isomer. It is isomerization.

Isomerization of long-chain hydrocarbons in the jet–diesel range is the last major HEFA process reaction step. Again, the reaction chemistry is complex, involves hard-to-control process conditions and unwanted side reactions at elevated temperatures and pressures, and uses a lot of

hydrogen. But these isomerization reactions, process conditions, and catalysts are markedly different from those of HDO.^{9 14–17 19 20} And these reactions, process conditions, catalysts and hydrogen requirements also depend upon whether isomerization is coupled with intentional hydrocracking to target jet instead of diesel fuel production.¹ Thus this last major set of HEFA process reactions has, so far, required a separate second step in HEFA refinery configurations. For example, MPC proposes to isomerize the hydrocrabons from its HDO reactors in a separate second-stage hydrocracking unit to be repurposed from its shuttered Martinez crude refinery.³

HEFA isomerization requires very substantial hydrogen inputs, and can recycle most of that hydrogen when targeting diesel production, but consumes much more hydrogen for intentional hydrocracking to boost jet fuel production, adding significantly to the already-huge hydrogen requirements for its HDO reaction step.¹

The role and impact of heat and pressure in the HEFA process

Hydro-conversion reactions proceed at high temperatures and extremely high pressures. Reactors feeding gas oils and distillates of similar densities to HEFA reactor feeds run at 575– 700 °F and 600–2,000 pounds per square inch (psi) for hydrotreating and at 575–780 °F and 600– 2,800 psi for hydrocracking.¹⁶ That is during normal operation. The reactions are exothermic: they generate heat in the reactor on top of the heat its furnaces send into it. Extraordinary steps to handle the severe process conditions become routine in hydro-conversion. Hydrogen injection and recycle capacities are oversized to quench and attempt to control reactor heat-and-pressure rise.^{16 22} When that fails, which happens frequently as shown in a following chapter, the reactors depressurize, dumping their contents to emergency flares. That is during petroleum refining.

Hydro-conversion reaction temperatures increase in proportion to hydrogen consumption,²¹ and HDO reactions can consume more hydrogen, so parts of HEFA hydro-conversion trains can run hotter than those of petroleum refineries, form more extreme "hot spots," or both. Indeed, HEFA reactors must be designed to depressurize rapidly.²² Yet as of this writing, no details of design potential HEFA project temperature and pressure ranges have been reported publicly.

1.2 Available option of repurposing hydrogen equipment drives choice of HEFA

Refiners could choose better new biofuel technology

Other proven technologies promise more flexibility at lower feedstock costs. For example, Fischer-Tropsch synthesis condenses a gasified mixture of carbon monoxide and hydrogen to form hydrocarbons and water, and can produce biogas, gasoline, jet fuel, or diesel biofuels.²³ Cellulosic biomass residues can be gasified for Fischer-Tropsch synthesis.²⁴ This alternative promises lower cost feedstock than HEFA technology and the flexibility of a wider range of future biofuel sales, along with the same ability to tap "renewable" fuel subsidies as HEFA technology. Refiners choose HEFA technology for a different reason.

Refiners can repurpose existing crude refining equipment for HEFA processing

Hydro-conversion reactors and hydrogen plants which were originally designed, built, and used for petroleum hydrocracking and hydrotreating could be repurposed and used for the new and different HEFA feedstocks and process reactions. This is in fact what the crude-to-biofuel refinery conversion projects propose to do in California.^{2 3 5 6}

In the largest HEFA project to be proposed or built, P66 proposes to repurpose its 69,000 barrel/day hydrocracking capacity at units 240 and 246 combined, its 16,740 b/d Unit 248 hydrotreater, and its 35,000 b/d Unit 250 hydrotreater for 100% HEFA processing at Rodeo.^{2 25} In the second largest project, MPC proposes to repurpose its 40,000 b/d No.2 HDS hydrotreater, 70,000 b/d No. 3 HDS hydrotreater, 37,000 b/d 1st Stage hydrocracker, and its 37,000 b/d 2nd Stage hydrocracker for 100% HEFA processing at Martinez.^{3 26}

For hydrogen production to feed the hydro-conversion processing P66 proposes to repurpose 28.5 million standard cubic feet (SCF) per day of existing hydrogen capacity from its Unit 110 and 120 million SCF/d of hydrogen capacity from the Air Liquide Unit 210 at the same P66 Rodeo refinery.^{2 25 27} MPC proposes to repurpose its 89 million SCF/d No. 1 Hydrogen Plant along with the 35 million SCF/d Air Products Hydrogen Plant No. 2 at the now-shuttered MPC Martinez refinery.^{3 4 11 26}

By converting crude refineries to HEFA biofuel refiners protect otherwise stranded assets

Motivations to protect otherwise stranded refining assets are especially urgent in the two largest crude-to-biofuel refining conversions proposed to date. Uniquely designed and permitted to rely on a landlocked and fast-dwindling crude source already below its capacity, the P66 San Francisco Refinery has begun to shutter its front end in San Luis Obispo County, which makes its unheated pipeline unable to dilute and send viscous San Joaquin Valley crude to Rodeo.²⁸ This threatens the viability of its Rodeo refining assets—as the company itself has warned.²⁹ The MPC Martinez refinery was shut down permanently in a refining assets consolidation, possibly accelerated by COVID-19, though the pandemic closed no other California refinery.³⁰

The logistics of investment in new and repurposed HEFA refineries as a refining asset protection mechanism leads refiners to repurpose a refining technology that demands hydrogen, then repurpose refinery hydrogen plants that supply hydrogen, then involve other companies in a related sector—such as Air Liquide and Air products—that own otherwise stranded hydrogen assets the refiners propose to repurpose as well.

Refiners also seek substantial public investments in their switch to HEFA biofuels. Tepperman (2020)³¹ reports that these subsidies include federal "Blenders Tax" credits, federal "Renewable Identification Number" credits, and state "Low Carbon Fuel Standard" credits that one investment advisor estimated can total \$3.32 per gallon of HEFA diesel sold in California. Krauss (2020)³² put that total even higher at \$4.00 per gallon. Still more public money could be directed to HEFA jet fuel, depending on the fate of currently proposed federal legislation.³³

2. UPSTREAM — IMPACT OF FEEDSTOCK CHOICES

The types, amounts, and characteristics of energy feedstocks have repercussions across the energy system and environment. Choosing HEFA technology would lock into place a particular subset of the biomass carbon on our planet for use in energy production. It would further create a need for continued and potentially additional hydrogen use. This chapter evaluates the environmental impacts of feedstock acquisition and feedstock choices in HEFA production.

2.1 Proposed feedstock use by the Phillips 66, Marathon, and other California projects

2.1.1 Biomass volume

The proposed conversions at P66 and MPC, and attendant use of HEFA feedstocks, are very large in scale. P66 boasts that its Rodeo biorefinery would be the largest in the world.¹⁰ The feedstock capacity of its HEFA biorefinery proposed in Rodeo, CA reported by P66 is 80,000 barrels per day (b/d).² With a feedstock capacity of 48,000 b/d, the MPC Martinez, CA project could then be the second largest HEFA refinery to be proposed or built worldwide.³ The World Energy subsidiary, AltAir, expansion in Paramount, CA, which also plans to fully convert a petroleum refinery, would add 21,500 b/d of new HEFA feedstock capacity.⁵ And Global Clean Energy Holdings, Inc. plans to convert its petroleum refinery in Bakersfield, CA into a HEFA refinery⁶ with at least 15,000 b/d of new capacity. Altogether that totals 164,500 b/d of new HEFA feedstock capacity statewide.

The aggregate proposed new California feedstock demand is some 61–132 *times* the annual feedstock demand for HEFA refining in California from 2016–2019.³⁴ But at the same time, the proposed new California biofuel feed demand is only ten percent of California refinery demand for crude oil in 2019,³⁵ the year before COVID-19 forced temporary refining rate cuts.³⁶ This raises a potential for the new HEFA feed demand from crude-to-biofuel refinery conversions proposed here today to be only the beginning of an exponentially increasing trend.

2.1.2 Biomass type

HEFA technology, proposed at all of the California refineries currently proposing conversion to biofuel production, uses as feedstock triacylglycerols (TAGs) and fatty acids derived from TAGs (Chapter 1). Primary sources of these biomass lipids in concentrations and amounts necessary for HEFA processing are limited to oil crop plants, livestock fats, and fish oils. Existing U.S. biofuels production has tapped soybean oil, distillers corn oil, canola oil, cottonseed oil, beef tallow, pork lard and grease, poultry fats, fish oils from an unreported and likely wide range of species, and used cooking oil—lipids that could be recovered from uses of these primary sources, also known as "yellow grease."^{37 38 39}

2.1.3 Other uses for this type of biomass

Importantly, people already use these oils and fats for many other needs, and they are traded globally. Beside our primary use of this type of biomass to feed ourselves directly, we use it to feed livestock in our food system, to feed our pets, and to make soap, wax, lubricants, plastics, cosmetic products, and pharmaceutical products.⁴⁰

2.2 Indirect impacts of feedstock choices

2.2.1 Land use and food system impacts

Growing HEFA biofuel feedstock demand is likely to increase food system prices. Market data show that investors in soybean and tallow futures have bet on this assumption.^{41 42 43} This pattern of radically increasing feedstock consumption and the inevitable attendant commodity price increases threatens significant environmental and human consequences, some of which are already emerging even with more modestly increased feedstock consumption at present.

As early as 2008, Searchinger et al.⁴⁴ showed that instead of cutting carbon emissions, increased use of biofuel feedstocks and the attendant crop price increases could expand crop land into grasslands and forests, reverse those natural carbon sinks, and cause food-sourced biofuels to emit more carbon than the petroleum fuels they replace. The mechanism for this would be global land use change linked to prices of commodities tapped for both food and fuel.⁴⁴

Refiners say they will not use palm oil, however, that alone does not solve the problem. Sanders et al. (2012)⁴⁵ showed that multi-nation demand and price dynamics had linked soy oil, palm oil, food, and biofuel feedstock together as factors in the deforestation of Southeast Asia for palm oil. Santeramo (2017)⁴⁶ showed that such demand-driven changes in prices act across the oil crop and animal fat feedstocks for HEFA biofuels in Europe and the U.S. Searle (2017)⁴⁷ showed rapeseed (canola) and soy biofuels demand was driving palm oil expansion; palm oil imports increase for other uses of those oils displaced by biofuels demand.

Additionally, The Union of Concerned Scientists (2015),⁴⁸ Lenfert et al. (2017),⁴⁹ and Nepstad and Shimada (2018)⁵⁰ linked soybean oil prices to deforestation for soybean plantations in the Brazilian Amazon and Pantanal. By 2017, some soy and palm oil biofuels were found to

emit more carbon than the petroleum fuels they are meant to replace.^{47 51} By 2019 the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services (IPBES) warned large industrial biofuel feedstock plantations threaten global biodiversity.⁵² By 2021 the Intergovernmental Panel on Climate Change joined the IPBES in this warning.⁵³ At high yields and prices, up to 79 million acres could shift to energy crops by 2030 in the U.S. alone.⁴⁰ And once a biofuel feedstock also used for food is locked in place, the human impacts of limiting land conversion could potentially involve stark social injustices, notably food insecurity and hunger.⁴⁴

Work by many others who are not cited here contributed to better understanding the problem of our growing fuel chain-food chain interaction. Potential biodiversity loss, such as pollinator population declines, further risks our ability to grow food efficiently. Climate heating threatens more frequent crop losses. The exact tipping point, when pushing these limits too hard might turn the natural carbon sinks that biofuels depend upon for climate benefit into global carbon sources, remains unknown.

2.1.2 Impact on climate solutions

Technological, economic, and environmental constraints across the arrays of proven technologies and measures to be deployed for climate stabilization limit biofuels to a targeted role in sectors for which zero-emission fuels are not yet available.^{53 54 55 56 57 58 59 60 61} And these technologies and measures require place-based deployment actions understood in a larger global context—actions that must be planned, implemented, and enforced by the political jurisdictions in each geography, but whose effect must be measured on a worldwide scale. California policy makers acted on this fact by expressly defining an in-state emission reduction which results in an emission increase elsewhere as inconsistent with climate protection.⁶²

Tapping a biomass resource for biofuel feedstock can only be part of our state or national climate solution if it does not lead to countervailing climate costs elsewhere that wipe out or overtake any purported benefits. Thus, if California takes biomass from another state or nation which that other state or nation needs to cut emissions there, it will violate its own climate policy, and more crucially, burning that biofuel will not cut carbon emissions. Moreover, our climate policy should not come at the cost of severe human and environmental harms that defeat the protective purpose of climate policy.

Use of biofuels as part of climate policy is thus limited by countervailing climate and other impacts. Experts that the state has commissioned for analysis of the technology and economics of paths to climate stabilization suggest that state biofuel use should be limited to the per capita share of sustainable U.S. production of biofuel feedstock.^{54 55} Per capita share is a valid benchmark, and is used herein, but it is not necessarily a basis for just, equitable, or effective policy. Per capita, California has riches, agriculture capacity, solar energy potential, and mild winters that populations in poorer, more arid, or more polar and colder places may lack. Accordingly, the per capita benchmark applied in Table 1 below should be interpreted as a conservative (high) estimate of sustainable feedstock for California HEFA refineries.

MM the million metric tons/vear

Table 1. U.S. and California lipid supplies v. potential new lipid feedstock demand from crude-to-biofuel refinery conversions now planned in California.

| www.by.minionmetric tons/year | | | | |
|-------------------------------|----------|-------------------|----------------------------|--------------------------|
| Lipids | U.S. | | CA per capita d | CA produced ^e |
| supply | (MM t/y) | (%) | (MM t/y) | (MM t/y) |
| Biofuels ^a | 4.00 | 100 % | 0.48 | 0.30 |
| All uses | 20.64 | 100 % | 2.48 | 1.55 |
| Soybean oil ^b | 10.69 | 52 % | | |
| Livestock fats a | 4.95 | 24 % | | |
| Corn oil ^b | 2.61 | 13 % | | |
| Waste oil ^a | 1.40 | 7 % | | |
| Canola oil ^b | 0.76 | 4 % | | |
| Cottonseed b | 0.23 | 1 % | | |
| Lipids Demand for four | | | | |
| proposed CA refineries | | Percentage of U.S | S. and California supplies | s for all uses |
| (MM t/y) ∘ | • | U.S. total | CA per capita | CA produced |
| 8.91 | | 43 % | 359 % | 575 % |

a. US-produced supply of feedstocks for hydro-processing esters and fatty acids (HEFA) in 2030, estimated in the U.S. Department of Energy *Billion-Ton Update* (2011).⁴⁰ Includes total roadside/farm gate yields estimates in the contiguous U.S. for biofuel feedstock consumption, and for all uses of animal fats and waste oil (used cooking oil).
 b. U.S. farm yield for all uses of lipids used in part for biofuels during Oct 2016–Sep 2020 from U.S. Department of Agriculture *Oil Crops Data: Yearbook Tables;* tables 5, 20, 26 and 33.³⁸ <u>See</u> also Karras (2021a).⁶³

c. From proposed Rodeo,² Martinez,³ Paramount⁵ and Bakersfield⁶ capacity at a feed specific gravity of 0.914.

d. California per capita share of U.S. totals based on 12 percent of the U.S. population.

e. Calif. produced lipids, after Billion-Ton Update by Mahone et al.,55 with lipids for all uses scaled proportionately.

2.3 Effect of supply limitations on feedstock acquisition impacts

Feeding the proposed new California HEFA refining capacity could take more than 350% of its per capita share from total U.S. farm yield for *all uses* of oil crop and livestock fat lipids that have been tapped for biofuels in much smaller amounts until now. <u>See</u> Table 1. The 80,000 b/d (~4.24 MM t/y) P66 Rodeo project² alone could exceed this share by ~71%. At 128,000 b/d (~6.79 MM t/y) combined, the P66² and Marathon³ projects together could exceed it by ~174%.

2.3.1 Supply effect on climate solutions

Emission shifting would be the first and most likely impact from this excess taking of a limited resource. The excess used here could not be used elsewhere, and use of the remaining farmed lipids elsewhere almost certainly would prioritize food. Reduced capacity to develop and use this biofuel for replacing petroleum diesel outside the state would shift future emissions.

2.3.2 <u>Supply effect on land use and food systems</u>

Displacement of lipid food resources at this scale would also risk cascading impacts. These food price, food security, and land conversion impacts fuel deforestation and natural carbon sink destruction in the Global South, and appear to have made some HEFA biofuels more carbon-

intensive than petroleum due to indirect land use impacts that diminish the carbon storage capacity of lands converted to biofuel plantations, as described above.^{41–53}

The severity of these risks to food security, biodiversity, and climate sinks appears uncertain for some of the same reasons that make it dangerous. Both the human factors that drove land use impacts observed in the past^{41–53} and the ecological resilience that constrained their severity in the past may not always scale in a linear or predictable fashion, and there is no precedent for the volume of lipid resource displacement for energy now contemplated.

In contrast, the causal trigger for any or all of these potential impacts would be a known, measurable volume of potential lipid biomass feedstock demand. Importantly, this volumedriven effect does not implicate the Low Carbon Fuel Standard and can only be addressed effectively by separate policy or investment actions.

2.3.3 Supply effect on HEFA feedstock choices

Both Marathon and P66 have indicated informally that their preferred feedstocks are used cooking oil "waste" and domestic livestock fats rather than soy and other food crop oils. It is clear, however, that supplies of these feedstocks are entirely insufficient to meet anticipated demand if the two conversions (and the others planned in California) move forward. Table 1 reveals the fallacy of assuming that used "waste" cooking oil or domestic livestock fats could feed the repurposed HEFA refineries, showing that supplies would be inadequate even in an extreme hypothetical scenario wherein biofuel displaces all other uses of these lipids.

As discussed below, these HEFA feedstock availability limitations have fuel chain repercussions for the other critical HEFA process input—hydrogen.

2.4 Impact of biomass feedstock choices on hydrogen inputs

2.4.1 <u>All HEFA feedstocks require substantial hydrogen inputs to convert the</u> triacylglycerols and fatty acids in the lipid feedstock into HEFA biofuels

Hydrogen (H₂) is the most abundant element in diesel and jet fuel hydrocarbons, and all of the lipid feedstocks that HEFA refiners could process need substantial refinery hydrogen inputs. In HEFA refining hydrogen bonds with carbon in lipid feeds to saturate them, to break the fatty acids and propane "knuckle" of those triacylglycerols apart, and—in unavoidable side-reactions or intentionally to make more jet fuel—to break longer carbon chains into shorter carbon chains. (Chapter 1.) Hydrogen added for those purposes stays in the hydrocarbons made into fuels; it is a true HEFA biofuel feedstock.

Hydrogen also bonds with oxygen in the lipids to remove that oxygen from the hydrocarbon fuels as water. *Id.* Forming the water (H₂O) takes two hydrogens per oxygen, and the lipids in HEFA feedstocks have consistently high oxygen content, ranging from 10.8–11.5 weight percent,¹ so this deoxygenation consumes vast amounts of hydrogen. Further, hydrogen is injected in large amounts to support isomerization reactions that turn straight-chain hydrocarbons

into branched-chain hydrocarbons. (Chapter 1.) And more hydrogen is injected to quench and control severe processing conditions under which all of these hydro-conversion reactions proceed. *Id.*

2.4.2 Some HEFA feedstocks need more hydrogen for HEFA processing than others

All types of HEFA feeds consume hydrogen in all the ways described above. However, how much is consumed in the first reaction—saturation—depends on the number of carbon double bonds in the fatty acids of the specific lipid feed source. <u>See</u> Diagram 1, Chapter 1. That matters because fatty acids in one specific HEFA lipids feed can have more carbon double bonds than fatty acids in another. Charts 1-A through 1–F below illustrate these differences in the fatty acid profiles of different HEFA feeds. The heights of the columns in these charts show the percentages of fatty acids in each feed that have various numbers of carbon double bonds.

In soybean oil, which accounts for the majority of U.S. oil crops yield shown in Table 1, most of the fatty acids have 2–3 carbon double bonds (Chart 1-A). In contrast, most of the fatty acids in livestock fats have 0–1 carbon double bonds (Chart 1-B). And in contrast to the plant oil *and* livestock fat profiles, which are essentially empty on the right side of charts 1-A and 1-B, a significant portion of the fatty acids in fish oils have 4–6 carbon double bonds (Chart 1-C).

Thus, HEFA processing requires more hydrogen to saturate the carbon double bonds in soy oil than those in livestock fats, and even more hydrogen to saturate those in fish oils. Such single-feed contracts are plausible, but feedstock acquisition logistics for the HEFA biofuels expansion—especially in light of the supply problem shown in Table 1—suggest refiners will process blends, and likely will process yield-weighted blends. Charts 1-D and 1-F show that such blends would dampen but still reflect these differences between specific plant oils, livestock fats, and fish oils. Finally, Chart 1-E illustrates the notoriously variable quality of used cooking oil (UCO), and Chart 1-F illustrates how the impact of UCO variability could be small compared with the differences among other feeds, since UCO could be only a small portion of the blend, as shown in Table 1.

2.4.3 Refining HEFA feedstocks demands more hydrogen than refining crude oil

Table 2, on the next page following the charts below, shows total hydrogen demand per barrel of feedstock, for processing different HEFA feeds, and for targeting different HEFA fuels.

Hydrogen demand for saturation of carbon double bonds ranges across the biomass feeds shown in Table 2 from 186–624 standard cubic feet of H₂ per barrel of biomass feed (SCF/b), and is the largest feedstock-driven cause of HEFA H₂ demand variability. For comparison, total on-purpose hydrogen production for U.S. refining of petroleum crude from 2006–2008, before lighter shale oil flooded refineries, averaged 273 SCF/b.¹⁶⁴ This 438 (624-186) SCF/b saturation range alone exceeds 273 SCF/b. The extra H₂ demand for HEFA feeds with more carbon double bonds is one repercussion of the livestock fat and waste oil supply limits revealed in Table 1.

A. Plant oils



B. Livestock fats



C. Fish oils

anchovy herring menhaden salmon tuna 60 50 % in feed 40 30 wt. 20 10 0 2 3 0 1 4 5 6 carbon double bonds



E. UCO variability (percentiles on C18:2) 10th Percentile 25th P 75th P 90th P



F. US yield-wtd. blend profiles, 0–25% fish oil 0% fish oil 0% fish oil 25% fish oil 25% fish oil 10th P UCO 90th P UCO 10th P UCO 90th P UCO 60



1. HEFA feed fatty acid profiles by number of carbon double bonds.

Carbon double bonds require more hydrogen in HEFA processing. **A–C.** Plant oil, animal fat and fish oil profiles. **D.** Comparison of weighted averages for plant oils (US farm yield-wtd. 70/20/7/3 soy/corn/canola/cottonseed blend), livestock fats (40/30/30 tallow/lard/poultry blend) and fish oils (equal shares for species in Chart 1C). **E.** UCO: used cooking oil, a highly variable feed. **F.** US yield-weighted blends are 0/85/10/5 and 25/60/10/5 fish/plant/livestock/UCO oils. Profiles are median values based on wt.% of linoleic acid. <u>See</u> Table A1 for data and sources.¹

| | Hydrodeoxygenation reactions | | Total with isomerization / cracking | |
|-------------------------------|------------------------------|-----------------------|-------------------------------------|-------------------|
| Biomass carbon feed | Saturation ^a | Others ^{b,c} | Diesel target | Jet fuel target d |
| Plant oils | | | | |
| Soybean oil | 479 | 1,790 | 2,270 | 3,070 |
| Plant oils blend ^e | 466 | 1,790 | 2,260 | 3,060 |
| Livestock fats | | | | |
| Tallow | 186 | 1,720 | 1,910 | 2,690 |
| Livestock fats blend e | 229 | 1,720 | 1,950 | 2,740 |
| Fish oils | | | | |
| Menhaden | 602 | 1,880 | 2,480 | 3,290 |
| Fish oils blend ^e | 624 | 1,840 | 2,460 | 3,270 |
| US yield-weighted blends e | | | | |
| Blend without fish oil | 438 | 1,780 | 2,220 | 3,020 |
| Blend with 25% fish oil | 478 | 1,790 | 2,270 | 3,070 |

Table 2. Hydrogen demand for processing different HEFA biomass carbon feeds.

Standard cubic feet of hydrogen per barrel of biomass feed (SCF/b)

a. Carbon double bond saturation as illustrated in Diagram 1 (a). **b, c.** Depropanation and deoxygenation as illustrated in Diagram 1 (b), (c), and losses to unwanted (diesel target) cracking, off-gassing and solubilization in liquids. **d.** Jet fuel total also includes H₂ consumed by intentional cracking along with isomerization. **e.** Blends as shown in charts 1-D and 1-F. Data from Tables A1and Appendix at A2.¹ Figures may not add due to rounding.

Moreover, although saturation reaction hydrogen alone can exceed crude refining hydrogen, total hydrogen consumption in HEFA feedstock processing is larger still, as shown in Table 2.

Other hydrodeoxygenation reactions—depropanation and deoxygenation—account for most of the total hydrogen demand in HEFA processing. The variability in "other" hydrogen demand mainly reflects unavoidable hydrogen losses noted in Table 2, which rise with hydro-conversion intensity. Targeting maximum jet fuel rather than diesel production boosts total HEFA hydrogen demand by approximately 800 SCF/b.¹⁹⁶⁵ This is primarily a product slate rather than feed-driven effect: maximizing jet fuel yield from the HDO reaction hydrocarbons output consumes much more hydrogen for intentional hydrocracking, which is avoided in the isomerization of a HEFA product slate targeting diesel.

Total hydrogen demand to process the likely range of yield-weighted biomass blends at the scale of planned HEFA expansion could thus range from 2,220–3,070 SCF/b, fully 8–11 *times* that of the average U.S. petroleum refinery (273 SCF/b).¹⁶⁴ This has significant implications for climate and community impacts of HEFA refining given the carbon-intensive and hazardous ways that refiners already make and use hydrogen now.

3. MIDSTREAM — HEFA PROCESS ENVIRONMENTAL IMPACTS

This chapter assesses refinery carbon emissions, refinery explosion and fire hazards, and air pollution impacts from refinery flares in HEFA processing. As shown in Chapter 2, turning a petroleum refinery into a HEFA refinery increases its hydrogen input intensity. This increased hydrogen intensity is particularly problematic given that the proposed conversions are all based on plans to re-purpose existing fossil fuel hydrogen production and hydro-conversion processes (Chapter 1). Current refinery hydrogen production that refiners propose to re-purpose uses the extraordinarily carbon intense "steam reforming" technology. Additionally, refinery explosion, fire, and flare emission hazards associated with processing in hydro-conversion units which refiners propose to re-purpose intensify at the increased hydrogen feed rates HEFA processing requires. P66 proposes to repurpose 148.5 million standard cubic feet per day (MMSCFD) of existing steam reforming hydrogen production capacity and 120,740 barrels per day (b/d) of existing hydro-conversion capacity for its proposed HEFA refinery in Rodeo. *Id.* MPC proposes to repurpose 124 MMSCFD of steam reforming capacity and 147,000 b/d of hydro-conversion capacity for its proposed HEFA refinery in Martinez. *Id.*

3.1 Carbon impact of steam reforming in the HEFA process

The hydrogen intensity of HEFA processing makes emissions from supplying the hydrogen all the more important, and as noted, refiners propose to repurpose carbon-intensive steam reforming. This could boost HEFA refinery carbon emissions dramatically.

Steam reforming makes hydrogen by stripping it from hydrocarbons, and the carbon left over from that forms carbon dioxide (CO₂) that emits as a co-product. <u>See</u> Diagram 2. It is often called methane reforming, but refiners feed it other refining byproduct hydrocarbons along with purchased natural gas, and even more CO₂ forms from the other feeds. The difference illustrated in Diagram 2 comes out to 16.7 grams of CO₂ per SCF of H₂ produced from propane *versus* 13.9 grams CO₂/SCF H₂ produced from methane. Fossil fuel combustion adds more CO₂.



Heating the water and feed to make the mixture of superheated steam and hydrocarbons that react at 1,300–1,900 °F, and making the additional steam and power that drive its pumps and pressure, make steam reforming energy intensive. Natural gas and refinery process off gas burn for that energy. Combustion energy intensity, based on design capacities verified and permitted by local air officials, ranges across 11 hydrogen plants that serve or served Bay Area refineries, from 0.142–0.277 million joules (MJ) per SCF H₂ produced, with a median of 0.202 MJ/SCF across the 11 plants.¹ At the median, ~10 gCO₂/SCF H₂ produced emits from burning methane. That, plus the 13.9 g/SCF H₂ from methane feed, could emit 23.9 g/SCF. This median energy intensity (EI) for methane feed is one of the potential plant factors shown in Table 3 below.

Hydrogen plant factors are shown in Table 3 for two feeds—methane, and a 77%/23% methane/propane mix—and for two combustion energy intensities, a Site EI and the median EI from Bay Area data discussed above. The mixed feed reflects propane by-production in HEFA process reactions and the likelihood that this and other byproduct gases would be used as feed, fuel, or both. Site EI should be more representative of actual P66 and MPC plant factors, but details of how they will repurpose those plants have not yet been disclosed. Median EI provides a reference point for P66 and MPC plant factors, and is applied to the other projects in the statewide total at the bottom of the table.

Table 3 shows how high-carbon hydrogen technology and high hydrogen demand for hydroconversion of HEFA feeds (Chapter 2) combine to drive the carbon intensity of HEFA refining. At the likely hydrogen feed mix and biomass feed blend lower bound targeting diesel production, HEFA hydrogen plants could emit 55.3–57.9 kilograms of CO₂ per barrel of biomass feed. And in those conditions at the upper bound, targeting jet fuel, they could emit 76.4–80.1 kg/b.

| Table 3. CO ₂ emissions from hydrogen pro | oduction proposed for HEFA processing by |
|--|--|
| full scale crude-to-biofuel refinery | y conversions planned in California. |

| | Plant factora | Conversion demand (SCF/b)b | | Carbon intensity | Mass emission |
|-------------------------|---------------|----------------------------|-------------|------------------|---------------|
| | (g/SCF) | Lower bound | Upper bound | (kg/b) | (Mt/y) |
| P66 Rodeo | | | | | |
| Mixed feed d | | | | | |
| Site El a | 26.1 | 2,220 | 3,070 | 57.9 – 80.1 | 1.69 – 2.34 |
| Median El a | 24.9 | 2,220 | 3,070 | 55.3 – 76.4 | 1.61 – 2.23 |
| Methane d | | | | | |
| Site El a | 25.0 | 2,220 | 3,070 | 55.5 – 76.7 | 1.62 – 2.24 |
| Median El ª | 23.9 | 2,220 | 3,070 | 53.1 – 73.4 | 1.55 – 2.14 |
| MPC Martinez | | | | | |
| Mixed feed ^d | | | | | |
| Site EI a | 25.8 | 2,220 | 3,070 | 57.3 – 79.2 | 1.00 – 1.39 |
| Median El a | 24.9 | 2,220 | 3,070 | 55.3 – 76.4 | 0.97 – 1.34 |
| Methane d | | | | | |
| Site El a | 24.7 | 2,220 | 3,070 | 54.8 - 75.8 | 0.96 – 1.33 |
| Median El ª | 23.9 | 2,220 | 3,070 | 53.1 – 73.4 | 0.93 – 1.29 |
| Total CA Plans: | | | | | |
| P66, MPC, AltAir | | | | | |
| and GCE | | | | | |
| Mixed feed a, d | 25.8 | 2,220 | 3.070 | 57.3 - 79.2 | 3.51 – 4.86 |
| Methane a, d | 24.6 | 2,220 | 3.070 | 54.6 - 75.5 | 3.35 - 4.63 |
| | | _, | -, | 3 | 5.00 |

g: gram (CO₂) SCF: standard cubic foot (H₂) b: barrel (biomass feed) Mt: million metric tons

a. Plant factor energy intensity (EI) expressed as emission rate assuming 100% methane combustion fuel. Site EI is from plant-specific, capacity-weighted data; median EI is from 11 SF Bay Area hydrogen plants that serve or served oil refineries. CA total assumes site EIs for P66 and MPC and median EI for AltAir and GCE.
b. H₂ demand/b biomass feed: lower bound for yield-weighted blend with 0% fish oil targeting maximum diesel production; upper bound for yield-weighted blend with 25% fish oil targeting maximum jet fuel production. c. Mass emission at kg/b value in table and capacity of proposed projects, P66: 80,000 b/d; MPC: 48,000 b/d; Altair: 21,500 b/d; GCE: 18,500 b/d. d. Mixed feed is 77% methane and 23% propane, the approximate proportion of propane by-production from HEFA processing, and the likely disposition of propane, other process byproduct gases, or both; methane: 100% methane feed to the reforming and shift reactions. See Appendix for details.¹

Total CO₂ emissions from hydrogen plants feeding the currently proposed HEFA refining expansion proposed statewide could exceed 3.5 million tons per year—if the refiners only target diesel production. <u>See</u> Table 3. If they all target jet fuel, and increase hydrogen production to do so, those emissions could exceed 4.8 million tons annually. *Id*.

It bears note that this upper bound estimate for targeting jet fuel appears to require increases in permitted hydrogen production at P66 and MPC. Targeting jet fuel at full feed capacity may also require new hydrogen capacity a step beyond further expanding the 1998 vintage⁶⁶ P66 Unit 110 or the 1963 vintage⁶⁷ MPC No. 1 Hydrogen Plant. And if so, the newer plants could be less energy intensive. The less aged methane reforming merchant plants in California, for example, have a reported median CO₂ emission rate of 76.2 g/MJ H₂.⁶⁸ That is 23.3 g/SCF, close to, but

less than, the methane reforming median of 23.9 g/SCF in Table 3. Conversely, the belief, based on available evidence until quite recently, that methane emissions from steam reformers do not add significantly to the climate-forcing impact of their huge CO₂ emissions, might turn out to be wrong. Recently reported aerial measurements of California refineries⁶⁹ indicate that methane emissions from refinery hydrogen production have been underestimated dramatically. Thus, the upper bound carbon intensity estimates in Table 3 might end up being too high or too low. But questions raised by this uncertainty do not affect its lower bound estimates, and those reveal extreme-high carbon intensity.

Total CO₂ emissions from U.S. petroleum refineries averaged 41.8 kg per barrel crude feed from 2015–2017, the most recent period in which we found U.S. government-reported data for oil refinery CO₂ emitted nationwide.¹ At 55–80 kg per barrel biomass feed, the proposed HEFA hydrogen production *alone* exceeds that petroleum refining carbon intensity by 32–91 percent.

Additional CO₂ would emit from fuel combustion for energy to heat and pressure up HEFA hydro-conversion reactors, precondition and pump their feeds, and distill, then blend their hydrocarbon products. Unverified potential to emit calculations provided by one refiner¹ suggest that these factors could add ~21 kg/b to the 55–80 kg/b from HEFA steam reforming. This ~76–101 kg/b HEFA processing total would exceed the 41.8 kg/b carbon intensity of the average U.S. petroleum refinery by ~82–142 percent. Repurposing refineries for HEFA biofuels production using steam reforming would thus increase the carbon intensity of hydrocarbon fuels processing.

3.2 Local risks associated with HEFA processing

HEFA processing entails air pollution, health, and safety risks to workers and the surrounding community. One of these risks—the intensified catastrophic failure hazard engendered by the more intensive use of hydrogen for HEFA processing—renders HEFA refining in this respect more dangerous than crude processing.

3.2.1 HEFA processing increases refinery explosion and fire risk

After a catastrophic pipe failure ignited in the Richmond refinery sending 15,000 people to hospital emergency rooms, a feed change was found to be a causal factor in that disaster—and failures by Chevron and public safety officials to take hazards of that feed change seriously were found to be its root causes.⁷⁰ The oil industry knew that introducing a new and different crude into an existing refinery can introduce new hazards.⁷¹ More than this, as it has long known, side effects of feed processing can cause hazardous conditions in the same types of hydro-conversion units it now proposes to repurpose for HEFA biomass feeds,⁷¹ and feedstock changes are among the most frequent causes of dangerous upsets in these hydro-conversion reactors.¹⁶

But differences between the new biomass feedstock refiners now propose and crude oil are bigger than those among crudes which Chevron ignored the hazards of before the August 2012 disaster in Richmond—and involve oxygen in the feed, rather than sulfur as in that disaster.⁷⁰



Chevron Richmond Refinery, 6 Aug 2012. Image: CSB

This categorical difference between oxygen and sulfur, rather than a degree of difference in feed sulfur content, risks further "minimizing the accuracy, or even feasibility, of predictions based on historical data."⁷¹ At 10.8–11.5 wt. %, HEFA feeds have very high oxygen content,¹ while the petroleum crude fed to refinery processing has virtually none. Carbonic acid forms from that oxygen in HEFA processing. Carbonic acid corrosion is a known hazard in HEFA processing.²² But this corrosion mechanism, and the specific locations it attacks in the refinery, differ from those of the sulfidic corrosion involved in the 2012 Richmond incident. Six decades of industry experience with sulfidic corrosion⁷¹ cannot reliably guide—and could misguide—refiners that attempt to find, then fix, damage from this new hazard before it causes equipment failures.

Worse, high-oxygen HEFA feedstock boosts hydrogen consumption in hydro-conversion reactors dramatically, as shown in Chapter 2. That creates more heat in reactors already prone to overheating in petroleum refining. Switching repurposed hydrocrackers and hydrotreaters to HEFA feeds would introduce this second new oxygen-related hazard.

A specific feedback mechanism underlies this hazard. The hydro-conversion reactions are exothermic: they generate heat.^{16 21 22} When they consume more hydrogen, they generate more

heat.²¹ Then they get hotter, and crack more of their feed, consuming even more hydrogen,^{16 21} so "the hotter they get, the faster they get hot."¹⁶ And the reactions proceed at extreme pressures of 600–2,800 pound-force per square inch,¹⁶ so the exponential temperature rise can happen fast.

Refiners call these runaway reactions, temperature runaways, or "runaways" for short. Hydro-conversion runaways are remarkably dangerous. They have melted holes in eight-inchthick, stainless steel walls of hydrocracker reactors¹⁶—and worse. Consuming more hydrogen per barrel in the reactors, and thereby increasing reaction temperatures, HEFA feedstock processing can be expected to increase the frequency and magnitude of runaways.

High temperature hydrogen attack or embrittlement of metals in refining equipment with the addition of so much more hydrogen to HEFA processing is a third known hazard.²² And given the short track record of HEFA processing, the potential for other, yet-to-manifest, hazards cannot be discounted.

On top of all this, interdependence across the process system—such as the critical need for real-time balance between hydro-conversion units that feed hydrogen and hydrogen production units that make it—magnifies these hazards. Upsets in one part of the system can escalate across the refinery. Hydrogen-related hazards that manifest at first as isolated incidents can escalate with catastrophic consequences.

Significant and sometimes catastrophic incidents involving the types of hydrogen processing systems proposed for California HEFA projects are unfortunately common in crude oil refining, as reflected in the following incident briefs posted by *Process Safety Integrity*⁷² report:

- ⁶ Eight workers are injured and a nearby town is evacuated in a 2018 hydrotreater reactor rupture, explosion and fire.
- A worker is seriously injured in a 2017 hydrotreater fire that burns for two days and causes an estimated \$220 million in property damage.
- A reactor hydrogen leak ignites in a 2017 hydrocracker fire that causes extensive damage to the main reactor.
- Å A 2015 hydrogen conduit explosion throws workers against a steel refinery structure.
- ^b Fifteen workers die, and 180 others are injured, in a series of explosions when hydrocarbons flood a distillation tower during a 2005 isomerization unit restart.
- A vapor release from a valve bonnet failure in a high-pressure hydrocracker section ignites in a major 1999 explosion and fire at the Chevron Richmond refinery.
- A worker dies, 46 others are injured, and the community must shelter in place when a release of hydrogen and hydrocarbons under high temperature and pressure ignites in a 1997 hydrocracker explosion and fire at the Tosco (now MPC) Martinez refinery.
- A Los Angeles refinery hydrogen processing unit pipe rupture releases hydrogen and hydrocarbons that ignite in a 1992 explosion and fires that burn for three days.

- A high-pressure hydrogen line fails in a 1989 fire which buckles the seven-inch-thick steel of a hydrocracker reactor that falls on other nearby Richmond refinery equipment.
- An undetected vessel overpressure causes a 1987 hydrocracker explosion and fire.⁷²

These incidents all occurred in the context of crude oil refining. For the reasons described in this section, there is cause for concern that the frequency and severity of these types of hydrogen-related incidents could increase with HEFA processing.

Refiners have the ability to use extra hydrogen to quench, control, and guard against runaway reactions as described in Chapter 1, a measure which has proved partially effective and appears necessary for hydro-conversion processing to remain profitable. As a safety measure, however, it has proved ineffective so often that hydro-conversion reactors are equipped to depressurize rapidly to flares.^{16 22} And that last-ditch safeguard, too, has repeatedly failed to prevent catastrophic incidents. The Richmond and Martinez refineries were equipped to depressurize to flares, for example, during the 1989, 1997, 1999 and 2012 incidents described above. In fact, precisely because it is a last-ditch safeguard, to be used only when all else fails, flaring reveals how frequently these hazards manifest as potentially catastrophic incidents. *See* Table 4 for specific examples.

Indeed, despite current safeguards, hydro-conversion and hydrogen-related process safety hazards which their HEFA conversion projects could worsen contribute to significant flaring incidents at the P66 Rodeo and MPC Martinez refineries frequently. Causal analysis reports for significant flaring show that hydrogen-related hazard incidents occurred at those refineries a combined total of 100 times from January 2010 through December 2020.¹ This is a conservative estimate, since incidents can cause significant impacts without causing environmentally significant flaring, but still represents, on average, and accounting for the Marathon plant closure since April 2020, another hydrogen-related incident at one of those refineries every 39 days.¹

Sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these 100 reported process safety hazard incidents.¹ Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.¹ In other words, incidents escalated to refinery-level systems involving multiple plants frequently—a foreseeable consequence, given that both hydro-conversion and hydrogen production plants are susceptible to upset when the critical balance of hydrogen production supply and hydrogen demand between them is disrupted suddenly. In four of these incidents, consequences of underlying hazards included fires in the refinery.¹

Since switching to HEFA refining is likely to further increase the frequency and magnitude of these already-frequent significant process hazard incidents, and flaring has proven unable to prevent every incident from escalating to catastrophic proportions, catastrophic consequences of HEFA process hazards are foreseeable.

Table 4. Examples from 100 hydrogen-related process hazard incidents at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020.

| Date ^a | Refinery | Hydrodrogen-related causal factors reported by the refiner a |
|-------------------|----------|--|
| 3/11/10 | Rodeo | A high-level safety alarm during a change in oil feed shuts down Unit 240 hydrocracker hydrogen recycle compressor 2G-202, forcing the sudden shutdown of the hydrocracker |
| 5/13/10 | Martinez | A hydrotreater charge pump bearing failure and fire forces #3 HDS hydrotreater shutdown $^{\rm b}$ |
| 9/28/10 | Martinez | A hydrocracker charge pump trip leads to a high temperature excursion in hydrocracker reactor catalyst beds that forces sudden unplanned hydrocracker shutdown $^{\rm c}$ |
| 2/17/11 | Martinez | A hydrogen plant fire caused by process upset after a feed compressor motor short forces the hydrogen plant shutdown; the hydrocracker shuts down on sudden loss of hydrogen |
| 9/10/12 | Rodeo | Emergency venting of hydrogen to the air from one hydrogen plant to relieve a hydrogen overpressure as another hydrogen plant starts up ignites in a refinery hydrogen fire |
| 10/4/12 | Rodeo | A hydrocracker feed cut due to a hydrogen makeup compressor malfunction exacerbates a reactor bed temperature hot spot, forcing a sudden hydrocracker shutdown ^d |
| 1/11/13 | Martinez | Cracked, overheated and "glowing" hydrogen piping forces an emergency hydrogen plant shutdown; the loss of hydrogen forces hydrocracker and hydrotreater shutdowns |
| 4/17/15 | Martinez | Cooling pumps trip, tripping the 3HDS hydrogen recycle compressor and forcing a sudden shutdown of the hydrotreater as a safety valve release cloud catches fire in this incident ° |
| 5/18/15 | Rodeo | A hydrocracker hydrogen quench valve failure forces a sudden hydrocracker shutdown ^f |
| 5/19/15 | Martinez | A level valve failure, valve leak and fire result in an emergency hydrotreater shutdown |
| 3/12/16 | Rodeo | A Unit 240 level controller malfunction trips off hydrogen recycle compressor G-202, which forces an immediate hydrocracker shutdown to control a runaway reaction hazard ^g |
| 1/22/17 | Martinez | An emergency valve malfunction trips its charge pump, forcing a hydrocracker shutdown |
| 5/16/19 | Martinez | A recycle compressor shutdown to fix a failed seal valve forces a hydrocracker shutdown $^{\rm h}$ |
| 6/18/19 | Martinez | A control malfunction rapidly depressurized hydrogen plant pressure swing absorbers |
| 11/11/19 | Rodeo | A failed valve spring shuts down hydrogen plant pressure swing absorbers in a hydrogen plant upset; the resultant loss of hydrogen forces a sudden hydrotreater shutdown ⁱ |
| 2/7/20 | Martinez | An unprotected oil pump switch trips a recycle compressor, shutting down a hydrotreater |
| 3/5/20 | Rodeo | An offsite ground fault causes a power sag that trips hydrogen make-up compressors, forcing the sudden shutdown of the U246 hydrocracker ^j |
| 10/16/20 | Rodeo | A pressure swing absorber valve malfunction shuts down a hydrogen plant; the emergency loss of hydrogen condition results in multiple process unit upsets and shutdowns ^k |

a. Starting date of the environmentally significant flaring incident, as defined by Bay Area Air Quality Management District Regulation § 12-12-406, which requires causal analysis by refiners that is summarized in this table. An incident often results in flaring for more than one day. The 100 "unplanned" hydro-conversion flaring incidents these examples illustrate are given in Table A6 of this report. Notes b–k below further illustrate some of these examples with quotes from refiner causal reports. b. "Flaring was the result of an 'emergency' ... the #3 HDS charge pump motor caught fire" c. "One of the reactor beds went 50 degrees above normal with this hotter recycle gas, which automatically triggered the 300 lb/minute emergency depressuring system." d. "The reduction in feed rates exacerbated an existing temperature gradient ...higher temperature gradient in D-203 catalyst Bed 4 and Bed 5 ... triggered ... shutdown of Unit 240 Plant 2."
e. "Flaring was the result of an Emergency. 3HDS had to be shutdown in order to control temperatures within the unit as cooling water flow failed." f. "Because hydrocracking is an exothermic process ... [t]o limit temperature rise... [c]old hydrogen quench is injected into the inlet of the intermediate catalyst beds to maintain control of the cracking reactor."
g. "Because G-202 provides hydrogen quench gas which prevents runaway reactions in the hydrocracking reactor, shutdown of G-202 causes an automatic depressuring of the Unit 240 Plant 2 reactor" h. "Operations shutdown the Hydrocracker as quickly and safely as possible." i. "[L]oss of hydrogen Make-Up compressors."
k. "Refinery Emergency Operating Procedure (REOP)-21 'Emergency Loss of Hydrogen' was implemented."

3.2.2 HEFA processing would perpetuate localized episodic air pollution

Refinery flares are episodic air polluters. Every time the depressurization-to-flare safeguard dumps process gases in attempts to avoid even worse consequences, that flaring is uncontrolled open-air combustion. Flaring emits a mix of toxic and smog forming air pollutants—particulate matter, hydrocarbons ranging from polycyclic aromatics to methane, sulfur dioxide, hydrogen sulfide, and others—from partially burning off enormous gas flows. Most of the 100 incidents described above flared more than two million cubic feet of vent gas each, and many flared more than ten million.¹

The increased risk of process upsets associated with HEFA processing concomitantly creates increased risk to the community of acute exposures to air pollutants, with impacts varying with the specifics of the incident and atmospheric conditions at the time when flaring recurs.

In 2005, flaring was linked to episodically elevated local air pollution by analyses of a continuous, flare activity-paired, four-year series of hourly measurements in the ambient air near the fence lines of four Bay Area refineries.⁷³ By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares.^{74 75} These same significance thresholds were used to require P66 and MPC to report the hazard data described above.⁷⁵

Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the P66 Rodeo and MPC Martinez refineries discussed above *individually* exceeded a relevant environmental significance threshold for air quality. Therefore, by prolonging the time over which the frequent incidents continue, and likely increasing the frequency of this significant flaring, repurposing refineries for HEFA processing can be expected to cause significant episodic air pollution.

Environmental justice impacts

It bears significant note that the refinery communities currently living with episodic air pollution—which would potentially be worsened by the conversion to HEFA processing—are predominantly populated by people of color. In fact, refineries were found to account for 93% of the statewide population-weighted disparity between people of color and non-Hispanic whites in particulate matter emission burdens associated with all stationary source industries in the state cap-and-trade program.⁷⁶ These communities of color tend to suffer from a heavy pre-existing pollution burden, such that additional and disproportionate episodic air pollution exposures would have significant environmental justice implications.

4. DOWNSTREAM — IMPACT OF BIOFUEL CONVERSIONS ON CLIMATE PATHWAYS

This chapter assesses potential impacts of HEFA biofuels expansion on California climate plans and goals. Primary issues of concern are HEFA biofuel volume, total liquid combustion fuel volume, systemic effects of refining and hydrogen use which could create HEFA lock-in, and the timing of choices between zero-emission *versus* liquid combustion fuels. Benchmarks for assessing these impact issues are taken from state roadmaps for the array of decarbonization technologies and measures to be deployed over time to achieve state climate goals—herein, "climate pathways." The state has developed a range of climate pathways, which rely in large part on strategies for replacing petroleum with zero-emission fuels that HEFA growth may disrupt and which reflect, in part, tradeoffs between zero-emission and liquid combustion fuels. Section 4.1 provides background on these climate pathway benchmarks and strategies.

Section 4.2 compares a foreseeable HEFA growth scenario with state climate pathway benchmarks for HEFA biofuel volume, total liquid fuel volume and systemic effects of refining and hydrogen use through mid-century, and estimates potential greenhouse gas emissions. This assessment shows that HEFA biofuel growth has the potential to impact state climate goals significantly. Section 4.3 addresses the timing of choices between zero-emission and liquid combustion fuels, shows that a zero-emission hydrogen alternative could be deployed during a critical window for breaking carbon lock-in, and assesses HEFA growth impacts on the emission prevention, clean fuels development, and transition mitigation effectiveness of this alternative.

4.1 California climate goals and implementation pathway benchmarks background related to HEFA biofuel impact issues assessed

4.1.1 State climate goals and pathways that HEFA biofuels growth could affect

State climate goals call for cutting greenhouse gas emissions 80% below 1990 emissions to a 2050 target of 86.2 million tons per year,⁷⁷ for zero-emission vehicles (ZEVs) to be 100% of

light-duty vehicle (LDV) sales by 2035 and 100% of the medium- and heavy-duty vehicle (MDV and HDV) fleet by 2045,⁷⁸ and for achieving net-zero carbon neutrality by 2045.⁷⁹

Behind the net-zero goal lies a highly consequential tradeoff: deeper emission cuts require transforming hard-to-decarbonize uses of energy. Relying on carbon dioxide removal-and-sequestration (CDR) instead risks failure to cut emissions until too late. The state has begun to confront this tradeoff by developing climate pathways that range from near-zero carbon to high-CDR. These pathways show how various types of biofuels and other technologies and measures fit into lower-emission and higher-emission approaches to achieving state climate goals.

Pathway scenarios developed by Mahone et al. for the California Energy Commission (CEC),⁵⁴ Air Resources Board⁵⁵ and Public Utilities Commission,⁵⁶ Austin et al. for the University of California,⁵⁷ and Reed et al. for UC Irvine and the CEC⁵⁸ add semi-quantitative benchmarks to the 2050 emission target, for assessing refinery conversions to biofuels. They join other work in showing the need to decarbonize electricity and electrify transportation.^{54–61} Their work "bookends" the zero-carbon to high–CDR range of paths to state climate goals,⁵⁵ analyzes the roles of liquid hydrocarbon combustion fuels and hydrogen in this context,^{54–58} and addresses potential biomass fuel chain effects on climate pathways.^{54 55 57}

4.1.2 <u>State climate pathway liquid fuels volume benchmarks that HEFA biofuels growth</u> <u>could affect</u>

Total liquid transportation fuels benchmark: ~1.6 to 3.3 billion gallons by 2045

All state pathways to net-zero emissions cut liquid petroleum fuels use dramatically, with biofuels replacing only a portion of that petroleum. Chart 2 illustrates the "bookends" of the zero-carbon to high-CDR range of pathways for transportation reported by Mahone et al.⁵⁵



2. California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.

Adapted from Figure 8 in Mahone et al. (2020a⁵⁵). Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion factors. **CDR:** carbon dioxide removal (sequestration).
Total liquid hydrocarbon combustion fuels for transportation in 2045, including petroleum and biofuels, range among the pathways from approximately 1.6 to 3.3 billion gallons/year (Chart 2), which is roughly 9% to18% of statewide petroleum transportation fuels use from 2013–2017.⁵⁵ Liquid biofuels account for approximately 1.4 to 1.8 billion gallons/year, which is roughly 40% to 100% of liquid transportation fuels in 2045 (Chart 2). Importantly, up to 100% of the biofuels in these pathways would be derived from cellulosic biomass feedstocks^{57 80 81} instead of purpose-grown lipids which HEFA technology relies upon, as discussed below.

HEFA biofuels volume benchmark: zero to 1.5 billion gallons per year through 2045

Many State climate pathways exclude or cap HEFA biofuel. Mahone et al. assume biofuels included in the pathways use cellulosic residues that are not purpose-grown—and cap those fuels in most scenarios to the per capita state share of non-purpose-grown U.S. biomass supply.^{54 55} This excludes purpose-grown lipids-derived biofuels such as the HEFA biofuels. Austin et al.⁵⁷ assume a cap on lipids biomass that limits HEFA jet fuel and diesel use to a maximum of 0.5–0.6 and 0.8–0.9 billion gallons/year, respectively. Both Austin⁵⁷ and Mahone^{54 55} cite difficult-to-predict land use emissions as reasons to limit purpose-grown crop and lipid-derived biofuels *as pathway development constraints* rather than as problems with the Low Carbon Fuel Standard (LCFS). This report agrees with that view: the need and ability to limit HEFA volume is a climate pathway impact issue—and local land use impact issue—not a criticism of the LCFS. <u>See</u> Box below.

4.1.3 <u>Electrolysis hydrogen benchmarks for systemic energy integration that affect the timing of choices between zero-emission *versus* liquid combustion fuels</u>

To replace combustion fuels in hard-to-electrify sectors, state climate pathways rely in part on "energy integration" measures, which often rely on electrolysis hydrogen, as discussed below.

Hydrogen for hard-to-decarbonize energy uses

Hydrogen, instead of HEFA diesel, could fuel long-haul freight and shipping. Hydrogen stores energy used to produce it so that energy can be used *where* it is needed for end-uses of energy that are hard to electrify directly, and *when* it is needed, for use of solar and wind energy at night and during calm winds. Climate pathways use hydrogen for hard-to-electrify emission sources in transportation, buildings and industry, and to support renewable electricity grids.

What is renewable-powered electrolysis hydrogen?

Electrolysis produces hydrogen from water using electricity. Oxygen is the byproduct, so solar and wind-powered electrolysis produces zero-emission hydrogen. State climate pathways consider three types of electrolysis: alkaline, proton-exchange membrane, and solid oxide electrolyzers.^{55 58} The alkaline and proton-exchange membrane technologies have been proven in commercial practice.⁵⁸ Renewable-powered electrolysis plants are being built and used at increasing scale elsewhere,⁸² and California has begun efforts to deploy this technology.⁵⁸

Biofuels in the Low Carbon Fuel Standard (LCFS)

| What the LCFS does | What we still need to do in other ways |
|---|---|
| Reduces the carbon intensity (CI) of transportation fuels | Reduce carbon-based fuel volume and volume- related mass emissions |
| Reduces transportation fuels CI by increments, over increments of time | Avoid committing to fuels that would exceed 2045 climate targets despite early incremental CI cuts |
| Moves money from higher-CI to lower-CI fuel producers | Build long-lasting production only for those fuels which will not exceed 2045 climate targets |
| Applies to fuels sold for use in the state, including biofuels, fossil fuels, electricity and hydrogen fuels | Prevent imports that people elsewhere need for their own biomass-based food and fuel |
| Compares the CI of each biofuel to the CI of the petroleum fuel it could replace across the whole fuel chains of both. To move dollars from higher to lower CI fuel producers, a specific "lifecycle" CI number estimate is made for each biofuel, from each type of biomass production, biofuel production, and fuel combustion in transportation for that biofuel | Directly monitor all the worldwide interactions of biomass fuel and food chains—to find out <i>before</i> an impact occurs. For example, what if increasing demand for soy-based biofuel leads farmers to buy pastureland for soybean plantations, leading displaced ranchers to fell rainforest for pastureland in another environment, state, or country? |
| Relies on currently quantifiable data for carbon emissions from harvesting each specific type of biomass for biofuel. The LCFS <i>has to</i> do this to come up with the specific CI numbers it uses to incrementally reduce transportation fuels CI now | Realize that some serious risks need to be avoided before they become realities which can be fully quantified, find out which biofuels pose such risks, and avoid taking those serious risks |
| This report does not assess the performance of the LCFS for its intended purpose — that is beyond the report scope. <i>This report should not be interpreted as a criticism or endorsement of the LCFS.</i> | HEFA biofuel risks that the LCFS is not designed to address are assessed in this report. <i>There are other ways to address these HEFA risks.</i> |

Electrolysis is not the only proven hydrogen production technology considered in state climate pathways; however, it is the one that can store solar and wind energy, and electrolysis hydrogen can decarbonize hard-to-electrify emission sources without relying on CDR.

Renewable-powered electrolysis for zero-emission transportation

Renewable-powered electrolysis hydrogen could be critical for zero-emission transportation. Hydrogen fuel shares shown in Chart 2 represent fuel cell-electric vehicle (FCEV) fueling. Fuel cells in FCEVs convert the hydrogen back into electricity that powers their electric motors. Thus, hydrogen stored in its fuel tank is the "battery" for this type of electric vehicle. FCEVs can decarbonize transportation uses of energy where battery-electric vehicles (BEVs) might be more costly, such as long-haul freight and shipping, in which the size and mass of BEV batteries needed to haul large loads long distances reduce the load-hauling capacity of BEVs.

This zero-emission electrolysis hydrogen also plays a key role because it fuels FCEVs without relying on CDR. These zero-emission FCEVs appear crucial to the feasibility of the

state climate goal for a 100% ZEV medium- and heavy-duty fleet by 2045.⁷⁸ This raises a turnkey issue because—as the difference in hydrogen fuel share between the High-CDR and the Balanced pathways in Chart 2 reflects—both electrolysis and FCEVs are proven technologies, but they nevertheless face significant infrastructure deployment challenges.^{54–61}

In state climate pathways, renewable hydrogen use in transportation grows from an average of 1.24 million standard cubic feet per day (MMSCFD) in 2019⁸³ to roughly 1,020–1,080 MMSCFD by 2045.^{56–58} This 2045 range reflects different scenarios for the mix of BEVs and FCEVs in different vehicle classes. The low end excludes FCEV use in LDVs⁵⁸ while the high end is a "central scenario" that includes both BEV and FCEV use in all vehicle classes.⁵⁷

Renewable-powered electrolysis for future solar and wind power growth

Hydrogen produced by electrolysis can store solar and wind power energy, which supports the renewable energy growth needed to produce more zero-emission FCEV fuel by electrolysis. Electrolysis hydrogen plays a key role in the further growth of solar and wind energy resources, because it can store that energy efficiently for use overnight as well as over longer windless periods. The direct use of electricity for energy—in grid jargon, the "load"—occurs in the same instant that electricity is generated. This is a challenge for climate pathways because solar and wind power are intermittent electricity generators, while electricity use (load) is continuous, and varies differently from solar and wind power generation over time.

Substantial energy storage will be critical to a renewable electricity grid. There are other storage technologies such as ion batteries, compressed air, hydropower management and power-to-gas turbines, and climate pathways include multiple measures to balance renewable grids.^{54–61} However, electrolysis hydrogen is particularly beneficial because it can provide efficient long-term storage over wind cycles as well as short-term storage over solar cycles while fueling ZEV growth. Charts 3 A and B below illustrate the scale of the solar energy storage need.

Load, the thick black curve that does not change from Chart A to Chart B, shows how much electric power we need and when we need it. In the renewables scale-up scenario (B), the yellow above the load curve is peak solar generation that could be wasted ("curtailed") if it cannot be stored, and the red below the load curve indicates "blackouts" we could avoid by storage of the otherwise wasted energy for use when it gets dark. This is only an example on one hypothetical day, but to continue the illustration, the energy that storage could shift, from yellow above the load curve to red below it, compares to the energy stored in \sim 1,500 MMSCF of hydrogen.

State climate pathways assign electrolysis a key role in meeting part of this enormous gridbalancing need. Energy storage would be accomplished by a mix of technologies and measures, including renewable-powered electrolysis hydrogen and others.^{54–58} Increasing needs for energy storage in climate pathways become substantial before 2030, and the role of electrolysis hydrogen in this storage grows by up to approximately 420 MMSCFD by 2045.⁵⁸



3. California electricity load shape on 20 April: Actual in 2021 v. renewable power.

A high-renewables future will require short-term storage of peak solar power generation for use at night. <u>See</u> yellow above and red below the black line showing total electricity load that can be used at the time power is generated, in this example. Solar electrolysis hydrogen stored in the fuel tanks of zero-emission trucks could be a needed part of the solution. **a.** Data reported for 20 April 2021.⁸⁴ **b.** Example scenario scales up solar and wind data proportionately to replace total fossil and nuclear generation on this day.

Renewable-powered electrolysis hydrogen for least-cost energy integration measures

Climate pathway analyses underscore both the challenge and the benefits of integrating electrolysis hydrogen across the transportation and electricity sectors. The scale-up challenge appears urgent. From ~2.71 MMSCFD by the end of 2021,⁵⁸ in-state electrolysis capacity would reach ~1,440–1,500 MMSCFD by 2045 to meet all of the transportation and energy storage needs for hydrogen discussed above.^{56–58} Ramping to that scale, however, achieves economies of scale in electrolysis hydrogen production and fueling that overcome significant deployment barriers to growth of this zero-emission FCEV fuel; electrolysis hydrogen costs can be expected to fall from above to below those of steam reforming hydrogen around 2025–2035.^{55 56 58 84 85} Policy intervention to meet critical needs for earlier deployment is assumed to drive ramp-up.⁵⁸

Then, once deployed at scale, integration of electrolysis, transportation and the electricity grid can provide multiple systemic benefits. It can cut fuel costs by enabling FCEVs that are more efficient than diesel or biofuel combustion vehicles,⁸⁶ cut health costs by enabling zeroemission FCEVs,^{57 87} cut energy costs by using otherwise wasted peak solar and wind power,^{58 85} and enable priority measures needed to decarbonize hard-to-electrify energy emissions.^{54 55 57 58 85} From the perspective of achieving lower-risk climate stabilization pathways, renewable-powered electrolysis hydrogen may be viewed as a stay-in-business investment.

State climate pathway benchmarks for hydrogen energy storage, transportation fuel, and refining that HEFA biofuel growth could affect

Electrolysis hydrogen production in state pathways could reach ~ 420 MMSCFD for energy storage and approximately 1,020–1,080 MMSCFD for transportation, as noted above, and could grow due to a third need and opportunity, which also could be affected by HEFA biofuel growth. The Hydrogen Roadmap in state climate pathways includes converting petroleum refining to renewable hydrogen production,⁵⁸ an enormously consequential measure, given that current hydrogen capacity committed to crude refining statewide totals ~1,216 MMSCFD.⁸⁸

4.1.4 <u>Replacement of gasoline with BEVs would idle crude refining capacity for distillates</u> as well, accelerating growth of a petroleum diesel replacement fuels market that <u>ZEVs, biofuels, or both could capture</u>

BEVs could replace gasoline quickly

Gasoline combustion inefficiencies make battery electric vehicle (BEV) replacement of gasoline a cost-saving climate pathway measure. By 2015 BEVs may already have had lower total ownership cost than gasoline passenger vehicles in California.⁸⁹ BEVs go three times as far per unit energy as same-size vehicles burning gasoline,⁹⁰ have fewer moving parts to wear and fix—for example, no BEV transmissions—have a fast-expanding range, and a mostly-ready fuel delivery grid. Economics alone should make gasoline obsolete as fast as old cars and trucks wear out, strongly supporting the feasibility of state goals for BEVs and other zero-emission vehicles (ZEVs) to comprise 100% of light-duty vehicle (LDV) sales by 2035.⁷⁸ State climate pathways show that BEVs can be 30–100% of LDV sales by 2030–2035, 60–100% of LDV and medium-duty vehicle sales by 2030–2045, and comprise most of the California vehicle fleet by 2045.^{55 57} Electricity-powered LDVs and MDVs would thus replace gasoline relatively quickly.

Gasoline replacement would idle petroleum distillates production

Crude refining limitations force petroleum distillate production cuts as gasoline is replaced. Existing California refineries cannot make distillates (diesel and jet fuel) without coproducing gasoline. From 2010–2019 their statewide distillates-to-gasoline production volumes ratio was 0.601 and varied annually from only 0.550 to 0.637.⁹¹ This reflects hard limits on refining technology: crude distillation yields a gasoline hydrocarbon fraction, and refineries are designed and built to convert other distillation fractions to gasoline, not to convert gasoline to distillates. During October–December in 2010–2019, when refinery gasoline production was often down for maintenance while distillate demand remained high, the median distillate-to-gasoline ratio rose only to 0.615.¹ That is a conservative estimate for future conditions, as refiners keep crude rates high by short-term storage of light distillation yield for gasoline production after equipment is returned to service.¹⁹¹ When gasoline and jet fuel demand fell over 12 months following the 19 March 2020 COVID-19 lockdown³⁶ the ratio fell to 0.515.⁹¹ Future permanent loss of gasoline markets could cut petroleum distillate production to less than 0.615 gallons per gallon gasoline. Climate pathways thus replace petroleum distillates along with gasoline.

Existing distillates distribution infrastructure favors biofuels, emphasizing the need for early deployment of FCEVs and zero-emission electrolysis hydrogen

Fuel cell-electric vehicle (FCEV) transportation faces a challenge in the fact that existing petroleum distillates distribution infrastructure can be repurposed to deliver drop-in biofuels to truck, ship, and jet fuel tanks, while hydrogen fuel infrastructure for FCEVs must ramp up. Hydrogen-fueled FCEV growth thus faces deployment challenges which biofuels do not.^{54–61} Those infrastructure challenges underly the urgent needs for early deployment of FCEVs and electrolysis hydrogen identified in state climate pathway analyses.^{54–58} Indeed, early deployment is an underlying component of the climate pathway benchmarks identified above.

4.2 HEFA biofuels growth could exceed state climate pathway benchmarks for liquid fuels volumes, interfere with achieving electrolysis hydrogen energy integration benchmarks, and exceed the state climate target for emissions in 2050

4.2.1 <u>HEFA biofuels growth could exceed state climate pathway benchmarks for liquid</u> <u>fuels volumes</u>

Proposed projects would exceed HEFA biofuel caps

Current proposals to repurpose in-state crude refining assets for HEFA biofuels could exceed the biofuel caps in state climate pathways by 2025. New in-state HEFA distillate (diesel and jet fuel) production proposed by P66, MPC, AltAir and GCE for the California fuels market would, in combination, total ~2.1 billion gal./y and is planned to be fully operational by 2025.¹⁻⁶ If fully implemented, these current plans alone would exceed the HEFA diesel and jet fuel caps of 0.0–1.5 billion gal./y in state climate pathways (§4.1.2).

Continued repurposing of idled crude refining assets for HEFA biofuels could exceed the total liquid combustion fuels volume benchmarks in state climate pathways

Further HEFA biofuels growth, driven by incentives for refiners to repurpose soon-to-bestranded crude refining assets before FCEVs can be deployed at scale, could exceed total liquid fuels combustion benchmarks for 2045 in state climate pathways. As BEVs replace petroleum distillates along with gasoline, crude refiners could repurpose idled petroleum assets for HEFA distillates before FCEVs ramp up (§ 4.1.4), and refiners would be highly incentivized to protect those otherwise stranded assets (Chapter 1).

Chart 4 illustrates a plausible future HEFA biofuel growth trajectory in this scenario. Declining petroleum diesel and jet fuel production forced by gasoline replacement with BEVs (gray-green, bottom) could no longer be fully replaced by currently proposed HEFA production (black) by 2025–2026. Meanwhile the idled crude refinery hydrogen production and processing assets repurpose for HEFA production (light brown, top). As more petroleum refining assets are stranded, more existing refinery hydrogen production is repurposed for HEFA fuels, increasing the additional HEFA production from left to right in Chart 4.





As electric vehicles replace gasoline, stranding petroleum refining assets, continuing HEFA biorefining expansion could add as much as 15 million gallons per day (290%) to the remaining petroleum distillatediesel and jet fuel refined in California by 2050. Locking in this combustion fuels additive could further entrench the incumbent combustion fuels technology in a negative competition with cleaner and lowercarbon technologies, such as renewable-powered hydrogen fuel cell electric vehicles (FCEVs). That could result in continued diesel combustion for long-haul freight and shipping which might otherwise be decarbonized by zero emission hydrogen-fueled FCEVs.

Petroleum-trajectory for cuts in petroleum refining of distillate (D) and jet (J) fuels that will be driven by gasoline replacement with lower-cost electric vehicles, since petroleum refineries cannot produce as much D+J when cutting gasoline (G) production. It is based on 5.56%/yr light duty vehicle stock turnover and a D+J:G refining ratio of 0.615. This ratio is the median from the fourth quarter of 2010–2019, when refinery gasoline production is often down for maintenance, and is thus relatively conservative. Similarly, state policy targets a 100% zero-emission LDV fleet by 2045 and could drive more than 5.56%/yr stock turnover. Values for 2020–2021 reflect the expected partial rebound from COVID-19.

HEFA-imports and **HEFA-existing** are the mean D+J "renewable" volumes imported, and refined in the state, respectively, from 2017–2019. The potential in-state expansion shown could squeeze out imports.

HEFA-proposed is currently proposed new in-state capacity based on 80.9% D+J yield on HEFA feed including the Phillips 66 Rodeo, Marathon Martinez, Altair Paramount, and GCE Bakersfield projects, which represent 47.6%, 28.6%, 12.8%, and 11.0% of this proposed 5.71 MM gal/day total, respectively.

HEFA-plausible: as it is idled along the petroleum-based trajectory shown, refinery hydrogen capacity is repurposed for HEFA biofuel projects, starting in 2026. This scenario assumes feedstock and permits are acquired, less petroleum replacement than state climate pathways,⁵⁵ and slower HEFA growth than new global HEFA capacity expansion plans targeting the California fuels market⁹² anticipate. Fuel volumes supported by repurposed hydrogen capacity are based on H₂ demand for processing yield-weighted feedstock blends with fish oil growing from 0% to 25%, and a J:D product slate ratio growing from 1:5.3 to 1:2, during 2025–2035.

For data and methodological details see Table A7.1

Refining and combustion of HEFA distillates in California could thus reach ~15.0 million gal./d (5.47 billion gal./y), ~290% of the remaining petroleum distillates production, by 2050.^{1.} HEFA distillate production in this scenario (5.47 billion gal./y) would exceed the 1.6–3.3 billion gal./y range of state climate pathways for combustion of *all* liquid transportation fuels, including petroleum and biofuel liquids, in 2045.⁵⁵ This excess combustion fuel would squeeze out cleaner fuels, and emit future carbon, from a substantial share of the emergent petroleum distillate fuels replacement market—a fuel share which HEFA refiners would then be motivated to retain.

This climate impact of HEFA biofuels growth is reasonably foreseeable

The scenario shown in Chart 4 is an illustration, not a worst case. It assumes slower growth of HEFA biofuel combustion in California than global investors anticipate, less petroleum fuels replacement than state climate pathways, and no growth in distillates demand. Worldwide, the currently planned HEFA refining projects targeting California fuel sales total ~5.2 billion gal./y by 2025.⁹² HEFA growth by 2025 in the Chart 4 scenario is less than half of those plans. State climate pathways reported by Mahone et al.⁵⁵ replace ~92% of current petroleum use by 2045, which would lower the petroleum distillate curve in Chart 4, increasing the potential volume of petroleum replacement by HEFA biofuel. Further, in all foreseeable pathways, refiners would be incentivized to protect their assets and fuel markets—and there are additional reasons why HEFA biofuel could become locked-in, as discussed below.

4.2.2 <u>Continued use of steam reforming for refinery hydrogen could interfere with meeting</u> state climate pathway benchmarks for electrolysis hydrogen energy integration, and lock HEFA biofuels in place instead of supporting transitions to zero-emission fuels

In contradiction to the conversion of refineries to renewable hydrogen in state climate pathways (§4.1.3), refiners propose to repurpose their high-carbon steam reforming hydrogen production assets for HEFA biofuels refining (chapters 1, 3). This would foreclose the use of that hydrogen for early deployment of ZEVs and renewable energy storage, the use of those sites for potentially least-cost FCEV fueling and renewable grid-balancing, and the future use of that hydrogen by HEFA refiners in a pivot to zero emission fuels. These potential impacts, together with HEFA refiner motivations to retain market share (§ 4.2.1), could result in HEFA diesel becoming a locked-in rather than a transitional fuel.

Repurposing refinery steam reforming for HEFA would circumvent a renewable hydrogen benchmark and interfere with early deployment for FCEVs and energy storage, slowing growth in ZEV hydrogen fuel and renewable energy for ZEV fuels production

Repurposing refinery steam reforming for HEFA fuels, as refiners propose,^{2–6} instead of switching crude refining to renewable hydrogen, as the hydrogen roadmap in state climate pathways envisions,⁵⁸ could foreclose a very significant deployment potential for zero-emission fuels. Nearly all hydrogen production in California now is steam reforming hydrogen committed to oil refining.⁵⁶ Statewide, crude refinery hydrogen capacity totals ~1,216 MMSCFD,⁸⁸ some 980 times renewable hydrogen use for transportation in 2019 (1.24 SCFD)⁸³ and ~450 times planned 2021 electrolysis hydrogen capacity (~2.71 MMSCFD).⁵⁸ Repurposing crude refining

hydrogen production for HEFA refining would perpetuate the commitment of this hydrogen to liquid combustion fuels instead of other potential uses. Importantly, that hydrogen would not be available for early deployment of FCEVs in the hard-to-electrify long haul freight and shipping sectors, or energy storage grid-balancing that will be needed for solar and wind power growth to fuel both zero emission FCEVs and BEVs.

By blocking the conversion of idled refinery hydrogen capacity to renewable hydrogen, repurposing idled crude refinery steam reforming for HEFA biofuels could slow ZEV fuels growth. Chart 5 below illustrates the scale of several potential impacts. Hydrogen demand for HEFA biofuels could exceed that for early deployment of FCEVs (Chart, 2025), exceed hydrogen demand for energy storage grid-balancing (Chart, 2045), and rival FCEV fuel demand for hydrogen in climate pathways through mid-century (*Id.*). ZEV growth could be slowed by foreclosing significant potential for zero-carbon hydrogen and electricity to produce it.

Repurposing refinery steam reforming could foreclose electrolysis deployment in key locations, potentially blocking least-cost FCEV fueling and grid-balancing deployment

Repurposing idled crude refinery steam reforming for HEFA biofuel production would foreclose reuse of otherwise idled refinery sites for renewable-powered electrolysis hydrogen. This site foreclosure impact could be important because of the potential electrolysis sites availability and location. Proximity to end-use is among the most important factors in the feasibility of renewable hydrogen build-out,⁵⁸ and refineries are near major California freight and shipping corridors and ports, where dense land uses make the otherwise idled sites especially useful for electrolysis siting. Repurposing crude refineries for HEFA biofuels could thus slow the rapid expansion of renewable-powered electrolysis hydrogen needed in climate pathways.

Continued use of steam reforming would lock HEFA refiners out of future ZEV fueling, further contributing to HEFA combustion fuels lock-in

Committing HEFA refineries to carbon-intensive steam reforming hydrogen would lock the refiners, who then would not be able to pivot toward future fueling of zero-emission FCEVs, into continued biofuel production. HEFA refiners would thus compete with hydrogen-fueled FCEVs in the new markets for fuels to replace petroleum diesel. In this HEFA growth scenario, the hydrogen lock-in, electrolysis site lockout, and ZEV fuel impacts described directly above could be expected to reinforce their entrenched position in those markets. This would have the effect of locking refiners into biofuels instead of ZEV fuels, thereby locking-in continued biofuel use at the expense of a transition to zero-emission fuels.

Crucially, multiple state pathway scenario analyses^{54–56 58} show that the simultaneous scaleup of FCEVs in hard-to-electrify sectors, renewable-powered electrolysis for their zero-emission fuel, and solar and wind power electricity to produce that hydrogen, already faces substantial challenges—apart from this competition with entrenched HEFA biofuel refiners.



5. Potential growth in hydrogen demand for HEFA biorefineries, fuel cell electric vehicle (FCEV) goods movement, and renewable electricity grid balancing to 2025 and 2045.

HEFA biorefineries could slow the growth of zero-emission goods movement, and of renewable electricity, by committing limited hydrogen supplies to drop-in diesel before the cleaner technologies ramp up (chart, 2025), by rivaling their demand for large new hydrogen supplies through mid-century (chart, 2045), and by committing to the wrong type of hydrogen production technology. H₂ supplied by electrolysis of water with renewable electricity could fuel FCEVs to decarbonize long-haul goods movement, and could store peak solar and wind energy to balance the electricity grid, enabling further growth in those intermittent energy resources. However, nearly all California H₂ production is committed to oil refining as of 2021. Refiners produce this H₂ by carbon-intensive steam reforming, and propose to repurpose that fossil fuel H₂ technology, which could not pivot to zero-emission FCEVs or grid balancing, in their crude-to-biofuel refinery conversions.

HEFA proposed based on H₂ demand estimated for P66 Rodeo, MPC Martinez, and other California HEFA projects proposed or in construction as of May 2021. H₂ demand increases from 2025–2045 as HEFA feedstock, jet fuel, and H₂/b demands increase. For data and methods details <u>see</u> Table A7.¹ **HEFA potential** based on H₂ production capacity at California petroleum refineries, additional to that for currently proposed projects, which could be idled and repurposed for potential HEFA projects along the trajectory shown in Chart 4. <u>See</u> Table A7 for data and details of methods.¹

FCEV Mid – HDV only from Mahone et al. (2020b),⁵⁶ FCEVs are ~2% and 50% of new heavy duty vehicle sales in California and other U.S. western states by 2025 and 2045, respectively.⁵⁶

Central – HDV & LDV from Austin et al. (2021), H₂ for California transportation, central scenario, LC1.⁵⁷ **High – HDV with grid balancing** from Reed et al. (2020), showing here two components of total demand from their high case in California: non-LDV H₂ demand in ca. 2025 and 2045, and H₂ demand for storage and firm load that will be needed to balance the electricity grid as solar and wind power grow, ca. 2045.⁵⁸

4.2.3 Potential carbon emissions could exceed the 2050 climate target

CO₂e emissions from the HEFA growth scenario were estimated based on LCFS carbon intensity values⁸⁶ weighted by the HEFA fuels mix in this scenario,¹ accounting for emission shifting effects described in Chapter 2. Accounting for this emission shift that would be caused by replacing petroleum with excess HEFA biofuel use in California at the expense of abilities to do so elsewhere—excluding any added land use impact—is consistent with the LCFS and state climate policy regarding emission "leakage."⁶² Results show that HEFA diesel and jet fuel CO₂e emissions in this scenario could reach 66.9 million tons (Mt) per year in 2050. <u>See</u> Table 5.

Table 5. Potential CO₂e emissions in 2050 from HEFA distillates refined and used in California.

| Distillates volume | | |
|---|-------|----------------------------------|
| HEFA distillates refined and burned in CA ^a | 5.47 | billion gallons per year |
| CA per capita share of lipid-based biofuel ^b | 0.58 | billion gallons per year |
| Excess lipids shifted to CA for HEFA biofuel ^c | 4.89 | billion gallons per year |
| Distillate fuels mix | | |
| HEFA diesel refined and burned in CA ^d | 66.7 | percentage of distillates |
| HEFA jet fuel refined and burned in CA ^d | 33.3 | percentage of distillates |
| Fuel chain carbon intensity | | |
| HEFA diesel carbon intensity ^e | 7.62 | kg CO₂e/gallon |
| HEFA jet fuel carbon intensity ^e | 8.06 | kg CO₂e/gallon |
| Petroleum diesel carbon intensity ^e | 13.50 | kg CO₂e/gallon |
| Petroleum jet fuel carbon intensity ^e | 11.29 | kg CO₂e/gallon |
| Emissions (millions of metric tons as CO ₂ e) | | |
| From CA use of per capita share of lipids | 4.50 | millions of metric tons per year |
| From excess CA HEFA use shifted to CA | 37.98 | millions of metric tons per year |
| Emissions shift to other states and nations ^f | 24.44 | millions of metric tons per year |
| Total HEFA distillate emissions | 66.92 | millions of metric tons per year |

a. Potential 2050 HEFA distillates refinery production and use in California in the scenario shown in Chart 4.1
b. Statewide per capita share of U.S. farm yield for all uses of lipids used in part for biofuels, from data in Table 1, converted to distillates volume based on a feed specific gravity of 0.914 and a 0.809 feed-to-distillate fuel conversion efficiency. Importantly, these purpose-grown lipids have other existing uses (Chapter 2).
c. Excess lipid biomass taken from other states or nations. This share of limited lipid biomass could not be used

c. Excess lipid biomass taken from other states or nations. This share of limited lipid biomass could not be used elsewhere to replace petroleum with HEFA biofuels. Per capita share of total U.S. production for all uses, rather than that share of lipids available for biofuel, represents a conservative assumption in this estimate.
 d. Distillate fuels mix in 2050 (1 gallon jet fuel to 3 gallons diesel) as described in Table A7 part f.¹

e. Carbon intensity (CI) values from tables 3, 7-1, and 8 of the California LCFS Regulation.⁸⁶ HEFA values used (shown) were derived by apportioning "fats/oils/grease residues" and "any feedstocks derived from plant oils" at 31% and 69%, respectively, based on the data in Table 1.

f. Future emissions that would not occur if other states and nations had access to the lipid feedstock committed to California biofuel refining and combustion in excess of the state per capita share shown. Shifted emissions based on the difference between HEFA and petroleum CI values for each fuel, applied to its fuels mix percent of excess lipid-based distillates shifted to CA for HEFA biofuel. Accounting for emissions caused by replacing petroleum in CA *instead of* elsewhere, separately from any added land use impact, is consistent with the LCFS and state climate policy regarding "leakage."⁶² Total emissions thus include shifted emissions.

Emissions from the remaining petroleum distillate fuels in this scenario, ~5,113,000 gal./d or 1.87 billion gal./y (Chart 4; Table A7¹), would add 22.1–24.2 Mt/y, if diesel is 25–75% of the 2050 petroleum distillates mix, at the petroleum carbon intensities in Table 5. Thus, distillate transportation fuel emissions alone (89–91 Mt/y) could exceed the 86.2 Mt/y 2050 state target for CO₂e emissions from all activities statewide.⁷⁷ Total 2050 emissions would be larger unless zeroed out in all other activities statewide. Repurposing idled petroleum refinery assets for HEFA biofuels threatens state climate goals.

4.3 A zero-emission electrolysis hydrogen alternative can be deployed during a crucial window for breaking carbon lock-in: HEFA biofuels growth could impact the timing, and thus the emission prevention, clean fuels development, and transition benefits, of this zero-emission electrolysis hydrogen alternative.

Potential benefits to climate pathways from converting hydrogen production to renewablepowered electrolysis (electrolysis) at refinery sites were assessed with and without HEFA biofuels expansion. The "HEFA Case" captures proposed and potential HEFA growth; the "No HEFA Case" is consistent state climate pathways that exclude purpose-grown lipids-derived biofuels in favor of cellulosic residue-derived biofuels.^{54 55} Conversion to electrolysis is assumed to occur at crude refineries in both cases, consistent with the hydrogen road map in state climate pathways,⁵⁸ but as an early deployment measure—assumed to occur during 2021–2026. This measure could reduce refinery carbon intensity, increase zero-emission transportation and electricity growth, and reduce local transition impacts significantly, and would be more effective if coupled with a cap on HEFA biofuels.

4.3.1 <u>Electrolysis would prevent HEFA biofuels from increasing the carbon intensity of</u> <u>hydrocarbon fuels refining</u>

Deployment timing emerges as the crucial issue in this analysis. "It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating. Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts."⁷⁰ The design phase for HEFA refinery conversions, and petroleum refinery turnarounds that occur on 3- to 5-year cycles are critical insertion points for electrolysis in place of carbon-intensive steam reforming. This zero-emission measure would cut the carbon intensity of refining at any time, however, climate stabilization benefit is directly related to the cumulative emission cut achieved, so the effectiveness of this measure would also depend upon how quickly it would be deployed.

Refining CI benefits in the HEFA Case

Replacing steam reforming with electrolysis could cut the carbon intensity (CI) of HEFA refining by \sim 72–79%, from \sim 76–101 kg/b to \sim 21 kg/b refinery feed (Chapter 3). This would cut the CI of HEFA fuels processing from significantly above that of the average U.S. petroleum refinery (\sim 50 kg/b crude; *Id.*) to significantly below the CI of the average U.S. crude refinery.

Refining CI benefits in the No HEFA Case

Replacing steam reforming with electrolysis at petroleum refineries would reduce CI by ~34% based on San Francisco Bay Area data,⁶⁶ however, in other states or nations where refiners run less carbon-intensive crude and product slates than in California, this ~34% may not apply.⁶⁴

Refining CI reduction effectiveness

Cumulative emission cuts from hydrogen production would be the same in both cases since hydrogen emissions would be eliminated from HEFA refineries in both cases. Based on the CI values above and the HEFA growth trajectory¹ in Chart 4 this measure could prevent ~194–282 million tons (Mt) of CO₂ emission from HEFA hydrogen production through 2050. Petroleum refinery emissions could be cut by 103 Mt through 2050, based on the median mixed feed CI of steam reforming (24.9 g/SCF, Table 3) and the remaining refinery hydrogen production underlying the distillates trajectory in Chart 4 from 2026–2050.¹ Total direct *cumulative* emissions prevented could be ~297–400 Mt. *Annual* fuel chain emissions from all distillates in transportation in 2050 (89–91 Mt/y) could be cut by ~12–16%, to ~76–78 Mt/y in the HEFA Case. In the No HEFA Case annual fuel chain emissions from petroleum distillates in 2050 (~22–24 Mt/y) could be cut by ~8–9%, to ~20–22 Mt/y, although use of other biofuels along with ZEVs could add to that 20–22 Mt/y significantly. This measure would be effective in all cases, and far more effective in climate pathways that cap HEFA growth and transition to ZEVs.

4.3.2 <u>Use of electrolysis would facilitate development of hydrogen for potential future use</u> in transportation and energy storage

Deployment timing again is crucial. Electrolysis can integrate energy transformation measures across transportation and electricity, speeding both FCEV growth and renewable power growth (§ 4.1). Benefits of this energy integration measure could coincide with a window of opportunity to break free from carbon lock-in, which opened with the beginning of petroleum asset stranding shown in Chapter 1 and could close if refiner attempts to repurpose those assets entrench a new source of carbon in the combustion fuel chain. As Seto et al. conclude:

"Understanding how and when lock-in emerges also helps identify windows of opportunity when transitions to alternative technologies and paths are possible [.] ... either in emergent realms and sectors where no technology or development path has yet become dominant and locked-in or at moments when locked-in realms and sectors are disrupted by technological, economic, political, or social changes that reduce the costs of transition"⁹³

Here, in a moment when the locked-in petroleum sector has been disrupted, and neither FCEV nor HEFA technology has yet become dominant and locked into the emergent petroleum diesel fuel replacement sector, this electrolysis energy integration measure could reduce the costs of transition if deployed at scale (§ 4.1). Indeed, state climate pathway analyses suggest that the need for simultaneous early deployment of electrolysis hydrogen, FCEVs, and energy storage load-balancing—and the challenge of scaling it up in time—are hard to overstate (§§ 4.1, 4.2).

Clean fuels development benefits in the HEFA Case

Converting refinery steam reforming to electrolysis during crude-to-biofuel repurposing before 2026 and at refineries to be idled and repurposed thereafter could provide electrolysis hydrogen capacities in 2025 and 2045 equivalent to the HEFA steam reforming capacities shown in Chart 5. However, HEFA refining would use this hydrogen, foreclosing its use to support early deployment of FCEVs and energy storage, and could further commit the share of future transportation illustrated in Chart 4 to liquid combustion fuel chain infrastructure.

Planned policy interventions could deploy electrolysis⁵⁸ and FCEVs⁷⁸ separately from refinery electrolysis conversions, although less rapidly without early deployment of this measure. If separate early deployment is realized at scale, this measure would enable HEFA refiners to pivot toward FCEV fueling and energy storage later. However, refinery combustion fuel share lock-in (§4.2) and competition with the separately developed clean hydrogen fueling could make that biofuel-to-ZEV-fuel transition unlikely, absent new policy intervention.

Clean fuels development benefits in the No HEFA Case

In the No HEFA Case, cellulosic residue-derived instead of HEFA biofuels would be in climate pathways,⁵⁵ and crude refinery steam reforming would be converted to electrolysis when it is idled before 2026 and in turnarounds by 2026. Instead of committing converted electrolysis hydrogen to HEFA refining as crude refining capacity is idled, it would be available for FCEVs and energy storage in the same amounts shown in Chart 5. This could fuel greater early FCEV deployment than state climate pathways assume (Chart, 2025), provide more hydrogen energy storage than in the pathways (Chart, 2045), and fuel most of the FCEV growth in the pathways through 2045 (*Id.*). These estimates from Chart 5 are based on the petroleum decline trajectory¹ underlying Chart 4, which is supported by economic drivers as well as climate constraints (§ 4.1) and assumes slower petroleum replacement through 2045 than state climate pathways (§ 4.2).

Clean fuels development benefits effectiveness

Energy integration benefits of this measure could be highly effective in supporting early deployment of zero-emission transportation during a crucial window of opportunity for replacing liquid hydrocarbon combustion fuels, and could fuel hydrogen storage as well as most zero-emission FCEV growth needs thereafter, in the No HEFA Case. In the HEFA Case, however, those benefits could be limited to an uncertain post-2030 future. These results further underscore the importance of limiting HEFA biofuel growth in state climate pathways.

4.3.3 <u>Use of electrolysis could lessen transition impacts from future decommissioning of converted refineries</u>

Just transitions, tailored to community-specific needs and technology-specific challenges, appear essential to the feasibility of climate stabilization.^{66 94} Full just transitions analysis for communities that host refineries is beyond the scope of this report, and is reviewed in more detail elsewhere.^{66 94} However, the recent idling of refining capacity, and proposals to repurpose it for HEFA biofuels, raise new transition opportunities and challenges for California communities

which were identified in this analysis, affect the feasibility of climate pathways, and thus are reported here. Hydrogen plays a pivotal role in the new transition challenges and opportunities which communities that host California refineries now face.

Transition benefits in the HEFA Case

Electrolysis would enable HEFA refineries to pivot from using hydrogen for biofuel to selling it for FCEV fuel, energy storage, or both. Assuming state climate pathways that replace transportation biofuels with ZEVs⁵⁷ achieve the state goal for 100% ZEV medium- and heavy-duty vehicles by 2045,⁷⁸ this would allow HEFA refiners to transition from HEFA biofuel hydroconversion processing while continuing uninterrupted hydrogen production at the same sites. Potential benefits would include reduced local job and tax base losses as compared with total facility closure, and eliminating the significant refinery explosion/fire risk and local air pollution impacts from HEFA hydro-conversion processing that are described in Chapter 3.

However, HEFA lock-in could occur before the prospect of such a biofuel-to-ZEV fuel transition could arise (§ 4.2). Conversions to electrolysis would lessen incentives for refiners to protect assets by resisting transition, and yet their fuel shares in emerging petroleum distillates replacement markets and incentives to protect those market shares would have grown (*Id.*).

Transition benefits in the No HEFA Case

In the No HEFA Case electrolysis hydrogen could pivot to FCEV fueling, energy storage, or both as petroleum refining capacity is idled in state climate pathways. Petroleum asset idling would be driven by economic factors that replace gasoline as well as climate constraints and thus be likely to occur (§ 4.1). Indeed, it has begun to occur (Chapter 1) and is likely to gather pace quickly (§§ 4.1, 4.2). Local job and tax base retention resulting from this hydrogen pivot in the No HEFA Case could be of equal scale as in the HEFA case. Local benefits from elimination of refinery hazard and air pollution impacts upon site transition would be from replacing petroleum refining rather than HEFA refining and would be realized upon crude refinery decommissioning rather than upon repurposed HEFA refinery decommissioning years or decades later.

Transition benefits effectiveness

Electrolysis hydrogen could have a pivotal role in just transitions for communities that host refineries. However, transition benefits of electrolysis would more likely be realized, and would be realized more quickly, in the No HEFA Case than in the HEFA Case. Realization of these potential transition benefits would be uncertain in the HEFA Case, and would be delayed as compared with the No HEFA Case.

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Supporting Material Appendix

for

Changing Hydrocarbons Midstream: Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing

Prepared for the Natural Resources Defense Council (NRDC) by Greg Karras, G. Karras Consulting <u>https://www.energy-re-source.com</u>

June 2021

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| Fatty acid (FA) in HI Fatty acid | EFA oil feed a FA | nd its triacyl FA | glycerol (T/ TAG | (G) ^d C=C bonds, | Complete h | ydro | deoxygenat | ion (| HDO) of tri | acyle | glycerol (| TAG) | | Hydrogen in | puts for co | nverting TAGs to grams H ₂ /kg TA(| drop-in diesel | Oxygen in TAG |
|-------------------------------------|----------------------|--|---|--------------------------------|---|------|---------------------|-------|-----------------------------------|--------|-------------------------------|------|--------------------|-------------|-------------|--|---------------------------|------------------|
| common name | Shorthan | d Formula | Formula | TAG of FA | TAG feed | + | Hydrogen - | 1 | oistillate - | 4 + | ropane | + | Water | TAG g/mol | HDO only | Lower Bound ^{c d} | Upper Bound ^{ed} | (wt. %) |
| Caprylic | C8:0 | C ₈ H ₁₆ O ₂ | C27H50O6 | 0 | C27H5006 | + | 12 H ₂ - | • | 3 C ₈ H ₁₈ | + | C ₃ H ₈ | + | 6 H ₂ O | 470.69 | 51.40 | 52.90 | 54.27 | 20.39 |
| Capric | C10:0 | C10H20O2 | C ₃₃ H ₆₂ O ₆ | 0 | C ₃₃ H ₆₂ O ₆ | + | 12 H ₂ - | 1 | 3 C10H22 | + | C ₃ H ₈ | + | 6 H ₂ O | 554.85 | 43.60 | 45.10 | 46.47 | 17.30 |
| Lauric | C12:0 | C12H24O2 | C ₃₉ H ₇₄ O ₆ | 0 | C ₃₉ H ₇₄ O ₆ | + | 12 H ₂ - | 1 | 3 C12H26 | + | C ₃ H ₈ | + | 6 H ₂ O | 639.02 | 37.86 | 39.36 | 40.73 | 15.02 |
| Myristic | C14:0 | C14H28O2 | C45H86O6 | 0 | C45H86O6 | + | 12 H ₂ - | 1 | 3 C14H30 | + | C ₃ H ₈ | + | 6 H ₂ O | 723.18 | 33.45 | 34.95 | 36.32 | 13.27 |
| Myristoleic | C14:1 | C14H26O2 | C45H80O6 | ю | C45H8006 | + | 15 H ₂ - | 1 | 3 C14H30 | + | C ₃ H ₈ | + | 6 H ₂ 0 | 717.13 | 42.17 | 43.67 | 45.04 | 13.39 |
| Pentadecanoic | C15:0 | C ₁₅ H ₃₀ O ₂ | C48H92O6 | 0 | C48H92O6 | + | 12 H ₂ - | 1 | 3 C ₁₅ H ₃₂ | + | C ₃ H ₈ | + | 6 H ₂ O | 759.21 | 31.86 | 33.36 | 34.73 | 12.64 |
| Palmitic | C16:0 | C ₁₆ H ₃₂ O ₂ | C ₅₁ H ₉₈ O ₆ | 0 | C ₅₁ H ₉₈ O ₆ | + | 12 H ₂ - | 1 | 3 C ₁₆ H ₃₄ | + | C ₃ H ₈ | + | 6 H ₂ O | 807.34 | 29.97 | 31.47 | 32.84 | 11.89 |
| Palmitoleic | C16:1 | C ₁₆ H ₃₀ O ₂ | C ₅₁ H ₉₂ O ₆ | ю | C ₅₁ H ₉₂ O ₆ | + | 15 H ₂ - | 1 | 3 C ₁₆ H ₃₄ | + | C ₃ H ₈ | + | 6 H ₂ O | 801.29 | 37.74 | 39.24 | 40.61 | 11.98 |
| Margaric | C17:0 | C17H34O2 | C ₅₄ H ₁₀₄ O ₆ | 0 | C54H104O6 | + | 12 H ₂ - | 1 | 3 C17H36 | + | C ₃ H ₈ | + | 6 H ₂ 0 | 849.42 | 28.48 | 29.98 | 31.35 | 11.30 |
| Stearic | C18:0 | C ₁₈ H ₃₆ O ₂ | C ₅₇ H ₁₁₀ O ₆ | 0 | C57H11006 | + | 12 H ₂ - | 1 | 3 C ₁₈ H ₃₈ | + | C ₃ H ₈ | + | 6 H ₂ O | 891.50 | 27.14 | 28.64 | 30.01 | 10.77 |
| Oleic | C18:1 | C ₁₈ H ₃₄ O ₂ | C57H104O6 | œ | C57H104O6 | + | 15 H ₂ - | 1 | 3 C ₁₈ H ₃₈ | + | C ₃ H ₈ | + | 6 H ₂ O | 885.45 | 34.15 | 35.65 | 37.02 | 10.84 |
| Linoleic | C18:2 | C ₁₈ H ₃₂ O ₂ | C ₅₇ H ₉₈ O ₆ | 9 | C ₅₇ H ₉₈ O ₆ | + | 18 H ₂ - | 1 | 3 C ₁₈ H ₃₈ | + | C ₃ H ₈ | + | 6 H ₂ O | 879.41 | 41.26 | 42.76 | 44.13 | 10.92 |
| Linolenic | C18:3 | C18H30O2 | C ₅₇ H ₉₂ O ₆ | 6 | C ₅₇ H ₉₂ O ₆ | + | 21 H ₂ - | 1 | 3 C ₁₈ H ₃₈ | + | C ₃ H ₈ | + | 6 H ₂ 0 | 873.36 | 48.47 | 49.97 | 51.34 | 10.99 |
| Stearidonic | C18:4 | C ₁₈ H ₂₈ O ₂ | C ₅₇ H ₈₆ O ₆ | 12 | C ₅₇ H ₈₆ O ₆ | + | 24 H ₂ - | 1 | 3 C ₁₈ H ₃₈ | + | C ₃ H ₈ | + | 6 H ₂ O | 867.31 | 55.79 | 57.29 | 58.66 | 11.07 |
| Arachidic | C20:0 | C ₂₀ H ₄₀ O ₂ | C ₆₃ H ₁₂₂ O ₆ | 0 | C ₆₃ H ₁₂₂ O ₆ | + | 12 H ₂ - | 1 | 3 C ₂₀ H ₄₂ | + | C ₃ H ₈ | + | 6 H ₂ O | 975.66 | 24.80 | 26.30 | 27.67 | 9.84 |
| Gondoic | C20:1 | C ₂₀ H ₃₈ O ₂ | C ₆₃ H ₁₁₆ O ₆ | ю | C ₆₃ H ₁₁₆ O ₆ | + | 15 H ₂ - | 1 | 3 C ₂₀ H ₄₂ | + | C ₃ H ₈ | + | 6 H ₂ O | 969.62 | 31.19 | 32.69 | 34.06 | 9.90 |
| Eicosadienoic | C20:2 | C ₂₀ H ₃₆ O ₂ | C ₆₃ H ₁₁₀ O ₆ | 9 | C ₆₃ H ₁₁₀ O ₆ | + | 18 H ₂ - | 1 | 3 C20H42 | + | C ₃ H ₈ | + | 6 H ₂ O | 963.57 | 37.66 | 39.16 | 40.53 | 96.6 |
| Homo-y-linoleic | C20:3 | C ₂₀ H ₃₄ O ₂ | C ₆₃ H ₁₀₄ O ₆ | 6 | C ₆₃ H ₁₀₄ O ₆ | + | 21 H ₂ - | 1 | 3 C ₂₀ H ₄₂ | + | C ₃ H ₈ | + | 6 H ₂ O | 957.52 | 44.21 | 45.71 | 47.08 | 10.03 |
| Arachidonic | C20:4 | C ₂₀ H ₃₂ O ₂ | C ₆₃ H ₉₈ O ₆ | 12 | C ₆₃ H ₉₈ O ₆ | + | 24 H ₂ - | 1 | 3 C20H42 | + | C ₃ H ₈ | + | 6 H ₂ O | 951.47 | 50.85 | 52.35 | 53.72 | 10.09 |
| Eicosapentaenoic | C20:5 | C ₂₀ H ₃₀ O ₂ | C ₆₃ H ₉₂ O ₆ | 15 | C ₆₃ H ₉₂ O ₆ | + | 27 H ₂ - | 1 | 3 C ₂₀ H ₄₂ | + | C ₃ H ₈ | + | 6 H ₂ O | 945.42 | 57.57 | 59.07 | 60.44 | 10.15 |
| Henicosanoic | C21:0 | C21H42O2 | C66H128O6 | 0 | C ₆₆ H ₁₂₈ O ₆ | + | 12 H ₂ - | 1 | 3 C21H44 | + | C ₃ H ₈ | + | 6 H ₂ O | 1017.74 | 23.77 | 25.27 | 26.64 | 9.43 |
| Heneicosapentaenc | nic C21:5 | C ₂₁ H ₃₂ O ₂ | C ₆₆ H ₉₈ O ₆ | 15 | C ₆₆ H ₉₈ O ₆ | + | 27 H ₂ - | 1 | 3 C ₂₁ H ₄₄ | + | C ₃ H ₈ | + | 6 H ₂ O | 987.50 | 55.12 | 56.62 | 57.99 | 9.72 |
| Behenic | C22:0 | C22H4402 | C ₆₉ H ₁₃₄ O ₆ | 0 | C ₆₉ H ₁₃₄ O ₆ | + | 12 H ₂ - | 1 | 3 C22H46 | + | C ₃ H ₈ | + | 6 H ₂ 0 | 1059.83 | 22.83 | 24.33 | 25.70 | 90.6 |
| Erucic | C22:1 | C ₂₂ H ₄₂ O ₂ | C ₆₉ H ₁₂₈ O ₆ | æ | C ₆₉ H ₁₂₈ O ₆ | + | 15 H ₂ - | 1 | 3 C ₂₂ H ₄₆ | + | C ₃ H ₈ | + | 6 H ₂ O | 1053.78 | 28.70 | 30.20 | 31.57 | 9.11 |
| Docosadienoic | C22:2 | C22H40O2 | C ₆₉ H ₁₂₂ O ₆ | 9 | C ₆₉ H ₁₂₂ O ₆ | + | 18 H ₂ - | 1 | 3 C22H46 | + | C ₃ H ₈ | + | 6 H ₂ 0 | 1047.73 | 34.63 | 36.13 | 37.50 | 9.16 |
| Docosatetraenoic | C22:4 | C ₂₂ H ₃₆ O ₂ | C ₆₉ H ₁₁₀ O ₆ | 12 | C ₆₉ H ₁₁₀ O ₆ | + | 24 H ₂ - | 1 | 3 C ₂₂ H ₄₆ | + | C ₃ H ₈ | + | 6 H ₂ O | 1035.63 | 46.72 | 48.22 | 49.59 | 9.27 |
| Docosapentaenoic | C22:5 | C22H34O2 | C69H104O6 | 15 | C ₆₉ H ₁₀₄ O ₆ | + | 27 H ₂ - | 1 | 3 C22H46 | + | C ₃ H ₈ | + | 6 H ₂ 0 | 1029.59 | 52.87 | 54.37 | 55.74 | 9.32 |
| Docosahexaenoic | C22:6 | C ₂₂ H ₃₂ O ₂ | C ₆₉ H ₉₈ O ₆ | 18 | C ₆₉ H ₉₈ O ₆ | + | 30 H ₂ - | 1 | 3 C ₂₂ H ₄₆ | + | C ₃ H ₈ | + | 6 H ₂ O | 1023.54 | 59.09 | 60.59 | 61.96 | 9.38 |
| Lignoceric | C24:0 | C24H48O2 | C75H146O6 | 0 | C75H146O6 | + | 12 H ₂ - | 1 | 3 C24H50 | + | C ₃ H ₈ | + | 6 H ₂ O | 1143.99 | 21.15 | 22.65 | 24.02 | 8.39 |
| Tetracosenoic | C24:1 | C ₂₄ H ₄₆ O ₂ | C ₇₅ H ₁₄₀ O ₆ | 3 | C ₇₅ H ₁₄₀ O ₆ | + | 15 H ₂ - | ^ | 3 C ₂₄ H ₅₀ | + | C ₃ H ₈ | + | 6 H ₂ 0 | 1137.94 | 26.57 | 28.07 | 29.44 | 8.44 |
| With all of a a day | 30 1 6 0000 | مليات فمادات | | | | | | | | | | | | | | | | |
| Whole reeds-see | oages 2-4 ur | this table. | | | | | | | | | | | | | | | | |

Table A1. HEFA Distillate Production Oil Feed and Hydrogen Data

| Whole feed oils and | fats | Selected plant | t oils, livesto | ock fats and f | ish oils | | | | | | | | | Us | ed cookin | ig oil (UCC |) variabili | lity |
|-----------------------------------|--------------|----------------|-----------------|----------------|-------------|------------|----------------|--------------|------------|------------------|------------|-----------|----------|-----------|-----------------------------------|--------------------|----------------------------------|--------|
| Fatty acid | FA | | | | Median of s | ample anal | /sis profile d | lata reporte | d based on | C18:2, in wt | * % . | | | <u>م</u> | ercentiles | s on C18:2 | ', in wt. % | * |
| Common name | Shorthand | Soybean | Corn | Canola Co | ttonseed | Palm | Tallow | Lard | Poultry | Anchovy | Herring Me | enhaden S | almon | Tuna 1(| 0 th P 25 ¹ | th P 75 | th P 90 th | P L |
| Caprylic | C8:0 | | | | | 0.186 | | | | | | | | | | | | |
| Capric | C10:0 | | | | | 0.324 | | 0.070 | | | | | | | | | | |
| Lauric | C12:0 | | | | | 2.284 | 1.010 | | | | | | | | | | | |
| Myristic | C14:0 | 0.100 | | 0.040 | 0.860 | 1.108 | 3.384 | 1.280 | 0.618 | 6.636 | 7.755 | 8.602 | 6.044 | 5.903 (| 0.909 2. | 479 1 | .735 | |
| Myristoleic | C14:1 | | | | | | | | 0.206 | | | | | 0.447 | | | | |
| Pentadecanoic | C15:0 | | | | | | | | | 0.701 | 0.408 | 0.538 | 0.769 | 0.359 | | | | |
| Palmitic | C16:0 | 11.000 | 12.860 | 4.248 | 23.600 | 41.480 | 24.495 | 25.000 | 24.206 | 16.355 | 15.306 | 21.505 | 17.143 1 | 17.670 20 | 0.606 20. | 248 16 | 412 12.4 | 420 |
| Palmitoleic | C16:1 | 0.100 | 0.100 | 0.287 | 0.360 | 0.167 | 4.040 | 3.000 | 6.951 | 7.757 | 8.469 | 10.108 | 2.198 | 5.961 4 | 1.646 | 1 | 735 | |
| Margaric | C17:0 | | | 0.069 | | 0.059 | 2.020 | 0.330 | 0.108 | 0.935 | 0.510 | 1.075 | 1.099 | 0.650 | | | | |
| Stearic | C18:0 | 4.000 | 1.760 | 1.752 | 2.400 | 4.186 | 17.525 | 12.540 | 5.814 | 3.738 | 2.143 | 3.333 | 2.637 | 4.155 4 | 1.848 12. | 810 5 | 235 5.7 | 760 |
| Oleic | C18:1 | 23.400 | 26.950 | 60.752 | 17.740 | 39.706 | 42.121 | 44.000 | 42.157 | 12.150 | 17.245 | 15.000 | 15.385 1 | 16.078 5 | 3.434 38. | 017 29 | 843 26.9 | 930 |
| Linoleic | C18:2 | 53.200 | 55.880 | 20.713 | 54.420 | 9.902 | 3.293 | 11.000 | 18.137 | 1.636 | 1.633 | 2.151 | 1.648 | 1.068 13 | 3.636 23. | 967 41 | 324 49.6 | 600 |
| Linolenic | C18:3 | 7.800 | 1.260 | 8.980 | 0.600 | 0.196 | 1.818 | 0.550 | 0.657 | 5.607 | 0.612 | 1.398 | 4.451 | 1.748 0 | 0.808 2. | 066 3 | 500 4.9 | 930 |
| Stearidonic | C18:4 | | | | | | | | | 2.336 | 2.551 | 3.333 | 3.077 | | | | | |
| Arachidic | C20:0 | 0.300 | 0.390 | 0.713 | 0.220 | 0.304 | 0.313 | 0.190 | | 0.841 | | 0.323 | 0.385 | 0.408 (| 0.121 | | 0.7 | 750 |
| Gondoic | C20:1 | | 0.280 | 1.277 | 0.070 | 0.078 | 0.081 | 0.800 | 0.392 | 3.738 | 11.224 | 1.075 | 1.978 | 4.922 (| 0.848 | | | |
| Eicosadienoic | C20:2 | | | | | | | 0.740 | | | | | | 0.272 | | | | |
| Homo-y-linoleic | C20:3 | | | | | | | 0.110 | | | | | | 3.437 | | | | |
| Arachidonic | C20:4 | | | | | | | 0.300 | | 2.103 | 0.408 | 1.720 | 2.967 | 0.184 | | | | |
| Eicosapentaenoic | C20:5 | | | | | | | | | 14.486 | 8.776 | 13.441 | 12.637 | 9.282 | | | | |
| Henicosanoic | C21:0 | | | | | | | | | | | | | | | | | |
| Heneicosapentaeno | ic C21:5 | | | | | | | | | 1.869 | | 0.806 | 2.582 | | | | | |
| Behenic | C22:0 | 0.100 | 0.120 | 0.307 | 0.110 | 0.039 | | | 0.118 | | | | | 0.078 0 | 0:030 | | | |
| Erucic | C22:1 | | | 0.594 | | | | | 0.098 | 3.224 | 15.102 | 0.645 | 660.9 | 0.311 0 | 0.071 | | | |
| Docosadienoic | C22:2 | | | | | | | | | | | | | | | | | |
| Docosatetraenoic | C22:4 | | 0.120 | | | | | | | | | | | | | | | |
| Docosapentaenoic | C22:5 | | 0.180 | | | | | | | 1.869 | 1.327 | 2.258 | 3.077 | 5.252 | | | | |
| Docosahexaenoic | C22:6 | | | | | | | | | 14.252 | 6.327 | 12.366 | 15.385 2 | 20.670 | | | | |
| Lignoceric | C24:0 | | | 0.099 | | 0.049 | | | 0.098 | | | | | 0.845 (| 0.040 | | | |
| Tetracosenoic | C24:1 | | | | | | | | 0.363 | | | | | 0.583 | | | | |
| Whole feed | | 11.00 | 10.995 | 10.862 | 11.190 | 11.446 | 11.277 | 11.146 | 11.178 | 10.844 | 10.738 | 11.026 | 10.639 1 | 10.720 11 | 1.128 11. | 081 11 | 084 11.0 | 046 |
| MW Secretific Gravitaut | g/mol | 873.1 | 872.3 | 881.6 | 865.9 | 844.4 | 856.1 | 861.9 | 859.7 | 898.9 0 0 0 0 | 901.8 | 874.2 | 904.2 | 911.4 8 | 364.4 8(| 51.0 8 010 0 | 63.8 87(| 6.6 |
| Diesel target H ₂ indu | it SCF/b oil | 2.274 | 2.237 | 2.162 | CCC.C | 1.961 | 1.908 | 2.080 | 1.877 | 2.558 | 075.0 | 0.481 | 012.0 | 0.524 | 0.026 2. | 031 2 | 160 2.2 | 218 |
| let fuel target H. inc | In SCE/h oil | 3 075 | 3 038 | 2 961 | 3 079 | 757 0 | 2 605 | 2 010 | 2 611 | 3 371 | 3 039 | 3 294 | 3 204 | 3 335 | C CC8 0 | C 100 | 056 2.0 | 014 |

Table A1. HEFA Distillate Production Oil Feed and Hydrogen Data, continued

| Eard blonds common | Cition furt 0/1 | Disst all blood* | 1 invetors fat /1 CE1 blond* | cich oil blood* | I I C viola woindated | *line doit fich oil * | II C viold woichtod b | *lin dig JEO/ tich nil* |
|-----------------------------------|-------------------|-------------------------------|-------------------------------------|-------------------------------|----------------------------|-----------------------|-----------------------|--------------------------|
| reed biends compo | SILION (WL. %) | Fiditi Oli Dienu | | rish oli biend | Diant all vield-weighted i | Diena, U% fish oil | U.S. yield-weignted t | 0. 25 /50/10/15 Flood |
| Latty actu | Chattand | | stbi (1) hour (1) hour (1) hour (1) | | | | | .0. 23/ 00/ 10/ 3 016110 |
| Canrolic Canrolic | Shortnand C8:0 | seea: 10/20/1/3 piena (wt. %) | 40/30/30 biena (wr. %) | saimon/tuna: 20% each (wt. %) | | 000 30 L | 000 10 | 000 30 F |
| Capric | C10:0 | | 0.022 | | 0.002 | 0.002 | 0.002 | 0.002 |
| Lauric | C12:0 | | 0.404 | | 0.040 | 0.040 | 0.040 | 0.040 |
| Myristic | C14:0 | 0.099 | 1.936 | 6.998 | 0.320 | 0.275 | 2.061 | 2.015 |
| Myristoleic | C14:1 | | 0.058 | 060.0 | 0.006 | 0.006 | 0.028 | 0.028 |
| Pentadecanoic | C15:0 | | | 0.555 | | | 0.140 | 0.140 |
| Palmitic | C16:0 | 11.284 | 24.578 | 17.615 | 13.057 | 12.647 | 14.650 | 14.241 |
| Palmitoleic | C16:1 | 0.121 | 4.523 | 6.924 | 0.780 | 0.548 | 2.495 | 2.264 |
| Margaric | C17:0 | 0.005 | 0.944 | 0.854 | 0.097 | 0.097 | 0.311 | 0.311 |
| Stearic | C18:0 | 3.347 | 12.652 | 3.207 | 4.338 | 4.383 | 4.300 | 4.345 |
| Oleic | C18:1 | 26.555 | 42.737 | 15.182 | 29.486 | 28.161 | 26.609 | 25.288 |
| Linoleic | C18:2 | 51.514 | 9.917 | 1.629 | 45.532 | 47.313 | 32.958 | 34.737 |
| Linolenic | C18:3 | 6.358 | 1.087 | 2.761 | 5.562 | 5.766 | 4.657 | 4.860 |
| Stearidonic | C18:4 | | | 2.259 | | | 0.570 | 0.570 |
| Arachidic | C20:0 | 0.345 | 0.186 | 0.392 | 0.318 | 0.349 | 0.330 | 0.361 |
| Gondoic | C20:1 | 0.147 | 0.398 | 4.597 | 0.207 | 0.165 | 1.330 | 1.287 |
| Eicosadienoic | C20:2 | | 0.237 | 0.055 | 0.023 | 0.023 | 0.037 | 0.037 |
| Homo-y-linoleic | C20:3 | | 0.035 | 0.690 | 0.003 | 0.003 | 0.178 | 0.178 |
| Arachidonic | C20:4 | | 0.096 | 1.473 | 0.009 | 600.0 | 0.381 | 0.381 |
| Eicosapentaenoic | C20:5 | | | 11.734 | | | 2.961 | 2.961 |
| Henicosanoic | C21:0 | | | | | | | |
| Heneicosapentaeno | ic C21:5 | | | 1.047 | | | 0.264 | 0.264 |
| Behenic | C22:0 | 0.119 | 0.033 | 0.016 | 0.106 | 0.104 | 0.080 | 0.078 |
| Erucic | C22:1 | 0.042 | 0.027 | 5.070 | 0.042 | 0.038 | 1.310 | 1.307 |
| Docosadienoic | C22:2 | | | | | | | |
| Docosatetraenoic | C22:4 | 0.024 | | | 0.020 | 0.020 | 0.014 | 0.014 |
| Docosapentaenoic | C22:5 | 0.036 | | 2.758 | 0.031 | 0.031 | 0.718 | 0.717 |
| Docosahexaenoic | C22:6 | | | 13.809 | | | 3.485 | 3.484 |
| Lignoceric | C24:0 | 0.007 | 0.027 | 0.170 | 0.011 | 600.0 | 0.052 | 0.050 |
| Tetracosenoic | C24:1 | | 0.102 | 0.117 | 0.010 | 0.010 | 0.040 | 0.039 |
| Whole feed | | 11.000 | 11.209 | 10.804 | 11.027 | 11.021 | 10.977 | 10.971 |
| MM | g/mol | 873.51 | 859.04 | 898.88 | 871.64 | 872.07 | 878.04 | 878.48 |
| Specific Gravity* | v. water | 0.916 | 006.0 | 0.925 | 0.914 | 0.914 | 0.916 | 0.916 |
| Diesel target H ₂ inpu | ut SCF/b oil | 2,258 | 1,950 | 2,460 | 2,215 | 2,225 | 2,266 | 2,275 |
| Jet fuel target H ₂ in | ou SCF/b oil | 3,059 | 2,737 | 3,269 | 3,014 | 3,024 | 3,067 | 3,076 |

Table A1. HEFA Distillate Production Oil Feed and Hydrogen Data, continued

| | Fish | | And | | | | | | | | | Soyb | l., | nco | | | | | | | | |
|------------------|-----------------|-----------------|-----------|-------|-------|-------|------|------|------|------|-------------|-----------------|-----------------|--------------------|-------|-------|-------|------|------|-------|-------|-------------|
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | Palm | 50.02 | 39.95 | 9.90 | 0.20 | 00.0 | 00.0 | 00.0 | 11.45 | | | | | | | | | | | |
| | | wt. % | ottonseed | 27.19 | 18.17 | 54.42 | 0.60 | 0.00 | 0.00 | 0.00 | 11.19 | | | 90 th P | 18.93 | 26.93 | 49.60 | 4.93 | 0.00 | 0.00 | 0.00 | 11.05 |
| | Se | s profile, in | Canola C | 7.23 | 62.91 | 20.71 | 8.98 | 0.00 | 0.00 | 0.00 | 10.86 | riability | 2, in wt. % * | 75 th P | 23.38 | 31.58 | 41.32 | 3.50 | 0.00 | 0.00 | 0.00 | 11.08 |
| | ation profile | Fatty acid | Corn | 15.13 | 27.33 | 55.88 | 1.26 | 0.12 | 0.18 | 0.00 | 10.99 | on profile va | iles on C18:2 | 25 th P | 35.54 | 38.02 | 23.97 | 2.07 | 0.00 | 0.00 | 0.00 | 11.08 |
| q | Plant oil satur | | Soybean | 15.50 | 23.50 | 53.20 | 7.80 | 0.00 | 0.00 | 0.00 | 11.00 | UCO saturatio | Percenti | 10 th P | 26.56 | 59.00 | 13.64 | 0.81 | 0.00 | 0.00 | 0.00 | 11.13 |
| continue | | | | | | | | | | | | | | | | | | | | | | |
| drogen Data, | ofiles | Nt. % | Poultry | 30.96 | 50.17 | 18.14 | 0.66 | 0.00 | 0.00 | 0.00 | 11.18 | ofiles | Nt. % | Fish oil | 29.81 | 31.98 | 1.68 | 3.45 | 3.73 | 15.54 | 13.81 | 10.80 |
| eed and Hy | saturation pr | s profile, in v | Lard | 39.41 | 47.80 | 11.74 | 0.66 | 0:30 | 00.0 | 00.0 | 11.15 | ck and fish pi | s profile, in v | LSF | 40.78 | 47.85 | 10.15 | 1.12 | 0.10 | 00.00 | 00.00 | 11.21 |
| roduction Oil F | Livestock fat s | Fatty acid | Tallow | 48.75 | 46.24 | 3.29 | 1.82 | 0.00 | 0.00 | 0.00 | 11.28 | Plant, livestoo | Fatty acid | Plant oil | 15.20 | 26.86 | 51.51 | 6.36 | 0.02 | 0.04 | 0.00 | 11.00 |
| EFA Distillate F | bonds per | whole feeds | C=C bonds | 0 | 1 | 2 | ß | 4 | 5 | 9 | tent, wt. % | bonds per | omparisons | C=C bonds | 0 | 1 | 2 | ю | 4 | 5 | 9 | tent, wt. % |
| Table A1. H | C=C double | fatty acid: v | FAx type | CX:0 | Cx:1 | Cx:2 | CX:3 | CX:4 | CX:5 | Cx:6 | Oxygen con | C=C double | fatty acid: c | FAx type | CX:0 | CX:1 | Cx:2 | CX:3 | CX:4 | CX:5 | Cx:6 | Oxygen con |

| N | | I | | | | | | | | |
|---|------------------|---------------------------------------|-------|-------|-------|------|------|------|------|--------------|
| rcentiles for UCO variabili | | % fish oil 90 th P UCO | 21.58 | 30.21 | 34.77 | 5.04 | 0.97 | 3.94 | 3.48 | 10 97 |
| il, at the 10 th and 90 th pe | ile, in wt. % | 5% fish oil 10 th P UCO 25 | 21.97 | 31.81 | 33.00 | 4.83 | 0.97 | 3.94 | 3.49 | 10 98 |
| es for 0% and 25% fish o | Fatty acids prof | % fish oil, 90 th P UCO 2 | 17.91 | 28.93 | 47.34 | 5.77 | 0.03 | 0.03 | 0.00 | 11 02 |
| U.S. yield-weighted blend profile | | 0% fish oil, 10 th P UCO 0 | 18.29 | 30.53 | 45.56 | 5.57 | 0.03 | 0.03 | 0.00 | 11 03 |
| onds per | spu | =C bonds | 0 | 1 | 2 | ŝ | 4 | 5 | 9 | nt wit % |
| C=C double bo | fatty acid: ble | FAx type C | CX:0 | CX:1 | Cx:2 | CX:3 | Cx:4 | Cx:5 | Cx:6 | Ovvgen conte |

| h oil satur | ation profil | es | | |
|-------------|--------------|-----------------|--------|-------|
| | Fatty ac | ids profile, in | wt.% | |
| nchovy | Herring | Menhaden | Salmon | Tuna |
| 29.21 | 26.12 | 35.38 | 28.08 | 30.07 |
| 26.87 | 52.04 | 26.83 | 25.66 | 28.30 |
| 1.64 | 1.63 | 2.15 | 1.65 | 1.34 |
| 5.61 | 0.61 | 1.40 | 4.45 | 5.18 |
| 4.44 | 2.96 | 5.05 | 6.04 | 0.18 |
| 18.22 | 10.10 | 16.51 | 18.30 | 14.53 |
| 14.25 | 6.33 | 12.37 | 15.39 | 20.67 |
| 10.84 | 10.74 | 11.03 | 10.64 | 10.72 |
| | | | | |

bean oil, canola oil and UCO variability

| % | UCO 90 th P | 18.93 | 26.93 | 49.60 | 4.93 | 00.00 | 00.00 | 00.00 | 11.05 |
|---------------|------------------------|-------|-------|-------|------|-------|-------|-------|-------|
| ofile, in wt. | Soybean | 15.50 | 23.50 | 53.20 | 7.80 | 0.00 | 0.00 | 0.00 | 11.00 |
| atty acids pr | Canola | 7.23 | 62.91 | 20.71 | 8.98 | 0.00 | 0.00 | 0.00 | 10.86 |
| Ę | 0 10 th P | 26.56 | 59.00 | 13.64 | 0.81 | 0.00 | 0.00 | 0.00 | 11.13 |

Supporting Material Appendix

page A 5

Explanatory notes and references for Table A1.

* Hydrotreating esters and fatty acids (HEFA) technology is limited to these carbon biomass lipid feeds as shown in the main report. Specific feeds shown are those that have been processed in the U.S., except for palm oil, which was shown for completeness. Median values were based on the median of the data cluster centered by the median value for C18:2 (linoleic acid) for each individual whole feed on the second page of Table A1. wt. %: weight percent; percentage of total mass. Specific gravity: the ratio of the density of a substance to the density of another substance that is taken as a standard, when both are weighed in air. The standard for measuring the Specific Gravity of an oil is water, which has an assigned value of 1.000. Thus, an oil that is 91.4% as dense as pure water has a specific gravity of 0.914. Feed blend ratios were based on the data and analysis in Chapter 2 of the main report and professional judgment. Blend data were not available for used cooking oil (UCO), except in the form of variability among blend samples collected, which showed UCO to be uniquely variable in terms of HEFA processing characteristics. This was shown as percentiles of the UCO sample distribution in the table. Values shown as red text in this table are feed-specific oxygen content in wt. %.

a. Triacylglycerols (TAGS) aka triglycerides, shown as pure fatty acids for simplicity. This does not affect the whole feed results in the table, which were based on data for specific distributions of fatty acids in each whole feed.

b. Reaction formulas shown for complete hydrodeoxygenation (HDO) assume ideal HDO reactions, and show stoichiometric hydrogen consumption for saturation, depropanation and deoxygenation only. *See* notes c and d below.

c. Hydrogen consumed or lost in catalyst protection, unwanted side-reaction cracking, feed decontamination, quench-cooling, venting and solubilization. <u>See</u> part A2 below. Hydrogen consumed or lost in these ways was estimated conservatively as 1.5 grams of hydrogen per kg of refinery feed, based on the data and analysis in part A2 below. This 1.5 g/kg estimate was applied in both the Lower Bound and the Upper Bound estimates shown in Table A1.

d. Upper Bound estimates reflect HEFA processing targeting maximum jet fuel production, which requires substantial on-purpose hydrocracking. <u>See</u> part A2 below. Upper Bound estimates in Table A1 were calculated from an additional hydrogen consumption by this on-purpose hydrocracking of 1.3 wt. % on feed, based on the data and analysis in part A2. Lower Bound estimates in Table A1 reflect processing targeting maximum diesel production and thus exclude this additional hydrogen consumption.

Data for whole feeds (e.g., soybean oil) were taken from the following sources: Soybean oil^{1 2 3 4 5 6 7 8} Corn oil (distillers corn oil)^{1 2 5 7 9 10 11 12} Canola oil (includes rapeseed oil)^{1-3 5-9 11 13 14 15} Cottonseed oil^{1 5 7-9} Palm oil^{1 3 5-10 16} Tallow (predominantly beef fat)^{1 6 11 13 17 18 19 20 21} Lard (pork fat)^{10 18 21} Poultry fat^{1 11 18 21 22} Anchovy²³ Herring^{24 25} Menhaden^{1 23 24} Salmon^{23 25} Tuna^{23 26 27} Used cooking oil (UCO)^{16 20 28 29 30 31 32 33 34}

Data references for Table A1.

¹ Satyarthi et al., 2013. *Catal. Sci. Technol.* 3:70. DOI: 10.1039/c2cy20415k.

² Tulcan et al., 2008. Analysis of Physical Characteristics of Vegetable Oils. CIGR–International

Conference of Agricultural Engineering, Brazil, 31 Aug-4 Sep 2008.

https://www.osti.gov/etdeweb/servlets/purl/21512209.

³ Han et al., 2013. *Bioresource Technology* 150: 447–456.

http://dx.doi.org/10.1016/j.biortech.2013.07.153.

⁴ Wang, 2002. *In* Gunstone, ed., Vegetable Oils in Food Technology. Blackwell: Oxford, UK.

⁵ Giakoumis, 2018. *Renewable Energy* Vol. 126: 403–419.

www.sciencedirect.com/science/article/abs/pii/S0960148118303689.

⁶ Phillips, 2019. Implications of Imported Used Cooking Oil as a Biodiesel Feedstock. NNFCC: Heslington, NY.

⁷ Canale et al., 2005. Int. J. Materials and Product Technology 24(1-4): 101–125.

https://www.inderscience.com/info/inarticle.php?artid=7943.

⁸ Zhao et al., 2017. *Catalysts* 7, 83. DOI: 10.3390/catal7030083.

⁹ Gunstone, ed., Vegetable Oils in Food Technology. Blackwell: Oxford, UK. 2002.

¹⁰ After Lindblom, S.C., Dozier, W.A. III, Shurson, G.C., and Kerr, B.J. 2017. Digestibility of energy and lipids and oxidative stress in nursery pigs fed commercially available lipids. J. Anim. Sci. 95: 239-247.

¹¹ Shurson et al., 2015. *Journal of Animal Science and Biotechnology* 6:10. DOI: 10.1186/s40104-015-0005-4.

¹² Kerr et al., 2016. J. Anim. Sci. 94: 2900–2908. doi: 10.2527/jas2016-0440.

¹³ Altun et al., 2010. Int. Journal of Engineering Research and Development Vol. 2, No. 2.

¹⁴ Vingering et al., 2020. *OCL* Vol. 17N° 3 MAI-JUIN 2020. doi: 10.1684/ocl.2010.0309. http://www.ocl-journal.org http://dx.doi.org/10.1051/ocl.2010.0309.

¹⁵ Orsavova et al., 2015. Int. J. Mol. Sci. 16: 12871–12890. doi: 10.3390/ijms160612871.

¹⁶ Awogbemi et al, 2019. *International Journal of Low-Carbon Technologies* 12: 417–425. doi: 10.1093/ijlct/ctz038.

¹⁷ Rezaei and Azizinejad, 2013. Journal of Food Biosciences and Technology 3.

¹⁸ Bitman, 1976. *In* Fat Content and Composition of Animal Products: Proceedings of a Symposium. National Academy of Sciences; https//doi.org/10.17226/22.

¹⁹ Application B0079, Kern Oil & Refining. GREET Pathway for the Production of Renewable Diesel from Animal Tallow. Submitted to Cal. Air Res. Board 31 March 2020.

²⁰ Pocket Information Manual, A Buyer's Guide to Rendered Products, National Renderers Association, Inc.: Alexandria, VA. 2003. www.renderers.org. Table e.

²¹ Adapted from Gunstone, F. 1996. Fatty Acid and Lipid Chemistry. Blackie: London, UK.

²² Chicken Fat; Fatty Acid Profile. In Material Safety Data Sheet: Chicken Fat. Darling Ingredients Inc.: Irving, TX. Date Prepared: 10 July 2012.

²⁵ Moffat and McGill, Ministry of Agriculture, Fisheries and Food: Torry Research Station, Aberdeen AB9 8DG. 1993. Variability of the composition of fish oils: significance for the diet. *Proceedings of the Nutrition Society* 52: 441–456. Printed in Great Britain. *After* Ackman and Eaton, 1966; Jangaard et al., 1967.

²⁶ Suseno et al., 2014. Fatty Acid Composition of Some Potential Fish Oil from Production Centers in Indonesia. *Oriental Journal of Chemistry* 30(3): 975–980. http://dx.doi.org/10.13005/ojc/300308.

²⁷ Simat et al., 2019. Production and Refinement of Omega-3 Rich Oils from Processing By-Products of Farmed Fish Species. *Foods* 8(125). doi: 10.3390/foods8040125.

²⁸ EUBIA, *after* Wen et al., 2010. http://www.eubia.org/cms/wiki-biomass/biomass-resources/challenges-related-to-biomass/used-cooking-oil-recycling.

²⁹ Knothe and Steidly, 2009. *Bioresource Technology* 100: 5796–5801. doi:

10.1016/j.biortech.2008.11.064.

³⁰ Banani et al., 2015. *J. Mater. Environ. Sci.* 6(4): 1178–1185. ISSN: 2028–2508. CODEN: JMESCN. http://www.jmaterenvironsci.com.

³¹ Chhetri et al., 2008. *Energies* 1: 3–8. ISSN 1996-1073. www.mdpi.org/energies. DOI: 10.3390/en1010003.

³² Yusuff et al., 2018. Waste Frying Oil as a Feedstock for Biodiesel Production. IntechOpen http://dx.doi.org/10.5772/intechopen.79433.

³³ Mannu et al., 2019. Variation of the Chemical Composition of Waste Cooking Oils upon Bentonite Filtration. *Resources* 8 (108). DOI: 10.3390/resources8020108.

³⁴ Mishra and Sharma, 2014. *J Food Sci Technol* 51(6): 1076–1084. DOI: 10.1007/s13197-011-0602-y.

²³ Xie et al., 2019. *Comprehensive Reviews in Food Science and Food Safety* Vol. 18. DOI: 10.1111/1541-4337.12427.

²⁴ Gruger, E, 1967. Fatty Acid Composition of Fish Oils. U.S. Dept. of Interior, Fish and Wildlife Service, Bureau of Commercial Fisheries: Washington, D.C. https://spo.nmfs.noaa.gov/content/circular-276-fatty-acid-composition-fish-oils.

A2. Hydrogen Losses, Isomerization Inputs, and Cracking Consumption.

After the feed is deoxygenated, an isomerization process converts its "waxy" saturated straightchain hydrocarbons to their "de-waxed" branched-chain isomers so that the final products will meet diesel and jet fuel specifications.¹ This requires large amounts of hydrogen to support isomerization catalyst activity, limit cracking reaction byproducts that poison the catalyst and reduce distillate fuel yields, and balance the heat, pressure, and flow rate in the reactor through hydrogen recycle "quenching."^{2 3 4} That recycling is imperfect. Unavoidable byproduct cracking reactions consume hydrogen with or without intentional (jet fuel) cracking,^{5 6} and still more H₂ escapes the process in the hydrocarbon stream and in scrubbing and purging byproduct gases.⁷ Roughly 1.5–3 wt. % of makeup hydrogen ends up being absorbed in reaction products.⁸ And even under relatively well-controlled conditions some 15–25 molar percent of the isomerization feed has been converted to non-distillate hydrocarbons by unwanted cracking.⁹

Longer, 15–18 carbon (C15–C18) hydrocarbon chains fed for HEFA diesel require more H₂ for adequately controlled isomerization than do shorter-chain (C4-C7) gasoline feeds.¹⁰ Also, isomerization of long-chain hydrocarbons uses more hydrogen in actual continuous operation than in bench-scale batch processing studies.¹¹ In long isomerization runs processing saturated straight-chain hydrocarbons with chain lengths to be used for drop-in biodiesel production (C15–C18), independent studies converged on an optimum H₂:feed ratio of 30:1 molar, which is approximately 5,120 standard cubic feet (SCF) hydrogen per barrel of isomerization unit feedstock.¹² This compares with hydrogen inputs to petroleum hydro-conversion processes that crack and isomerize diesel or gas oils ranging from roughly 1,600–4,490 SCF/barrel (SCFB).¹³

⁶ Regali et al. Hydroconversion of *n*-hexadecane on Pt/silica-alumina catalysts: Effect of metal loading and support acidity on bifunctional and hydrogenolytic activity. *Applied Catalysis* (**2014**) A: General 469: 328. http://dx.doi.org/10.1016/j.apcata.2013.09.048.

¹ Maki-Arvela et al. Catalytic Hydroisomerization of Long-Chain Hydrocarbons for the Production of Fuels. *Catalysts* (**2018**) 8: 534. DOI: 10.3390/catal8110534; Parmar et al. Hydroisomerization of *n*-hexadecane over Brønsted acid site tailored Pt/ZSM-12. *J Porous Mater* (**2014**). DOI: 10.1007/s10934-014-9834-3; Douvartzides et al. Green Diesel: Biomass Feedstocks, Production Technologies, Catalystic Research, Fuel Properties and Performance in Compression Ignition Internal Combustion Engines. *Energies* (**2019**) 12: 809. DOI: 10.3390/en12050809.

² Maki-Arvela et al. (2018); Parmar et al. (2014); Douvartzides et al. (2019).

³ Robinson and Dolbear. Commercial Hydrotreating and Hydrocracking. *In:* Hydroprocessing of heavy oils and residua. Ancheyta and Speight, *eds.* (2007.) CRC Press, Taylor & Francis Group: Boca Raton, FL. ISBN-13: 978-0-8493-74197.

⁴ Speight, J. G. (1991). The Chemistry and Technology of Petroleum; 2nd Edition, Revised and Expanded. *In* Chemical Industries, Vol. 44. ISBN 0-827-8481-2. Marcel Dekker: New York. <u>See</u> p. 491; Speight, J. G. (2013). Heavy and Extra-heavy Oil Upgrading Technologies. Elsevier: NY. ISBN: 978-0-12-404570-5. pp. 78–79, 92–93.
⁵ Maki-Arvela et al. (2018); Parmar et al. (2014); Douvartzides et al. (2019); Speight (1991) at 491.

⁷ Speight (2013) at 89–90; Speight (1991) at p. 578.

⁸ Speight (1991) at p, 578 (up to 1.5 wt.% of makeup H2 absorbed per stage of a typical two-stage hydrocracker).
⁹ Maki-Arvela et al. (2018) at Figure 15; *see* also figures 2, 9, 11.

¹⁰ Maki-Arvela et al. (2018); Regali et al. (2014); Douvartzides et al. (2019); Speight (1991) at 491.

¹¹ Maki-Arvela et al. (2018).

¹² Maki-Arvela et al. (2018) at pp. 22, 23.

¹³ <u>See</u> Robinson and Dolbear (2007); Speight (1991) at pp. 578–584; Meyers, R. A. (1986.) Handbook of Petroleum Refining Processes. *In* Chemical Process Technology Handbook Series. ISBN 0-07-041763-6. McGraw-Hill: NY. <u>See</u> pp. 5-16 and 5-17; Bouchy et al. (2009). Fischer-Tropsch Waxes Upgrading via Hydrocracking and Selective Hydroisomerization. *Oil & Gas Science and Technology—Rev.* 64(1): 91-112. DOI: 10.2516/ogst/2008047.

H₂ consumption in diesel isomerization can be estimated based on these figures for 5,120 SCFB input, 1.5–3% loss, and 15–25% cracking demand for H₂. Assuming that diesel production is targeted, the isomerization step in drop-in HEFA biofuel production could add approximately 102-196 SCFB (1.50-2.87 g/kg feed) to the total processing demand for hydrogen in the HEFA biorefinery. Table A2 shows the calculation data for this estimate.

| | | Lower Bound | Upper Bound |
|--|---------------------------------------|---------------|--------------|
| Total hydrogen injected per barrel feed ^b | (SCFB) | 5,120 | 5,120 |
| Solubility, scrubbing and purge losses $\ensuremath{^\circ}$ | (vol. %) (SCFB) | 1.5 % 76.8 | 3.0 % 154 |
| Cracking consumption | · · · · | | |
| Inadvertent cracking ^d | (molar feed %) | 15 % | 25 % |
| H ₂ consumption ^e | (g/kg feed) | 0.375 | 0.624 |
| H ₂ consumption ^f | (m ³ /m ³ feed) | 4.56 | 7.60 |
| H ₂ consumption ^g | (SCFB) | 25.6 | 42.7 |
| Total hydrogen consumed in isomerization | (SCFB) | 102 | 196 |
| | (g/kg feed) | 1.50 | 2.87 |

Table A2. Estimate calculation data for hydrogen consumption in C15–C18 feed isomerization targeting drop-in diesel biofuel production ^a

a. H₂ consumed by isomerization with intentional hydrocracking for jet fuel production could far exceed this estimate. b. From optimum on-stream hydrogen/feed ratio (30:1) reported by Maki-Arvela et al. (2018). See esp. pp. 22, 23. c. From Speight (1991) at 578; see also Speight (2013) at 89–90. d. From Maki-Arvela et al. (2018). See Fig. 15; see also figs. 2, 9, 11 in Maki-Arvela. See also note a (this table). e. Based on hydrogen bonding to each carbon as the carbon-carbon bond of the saturated hydrocarbon is cleaved, and H₂, feed molar weights of 2.016 and 807.3 grams, respectively, and the cracking % shown. f. From 89.9 g/m³ H₂, feed specific gravity of 0.914, and the data shown and noted above. g. From 0.0283168 SCF/m³ and 0.15898 m³/barrel.

Note that the estimate in Table A2 is for HEFA processing targeting diesel product; targeting jet fuel from the same feed would require substantial additional cracking along with isomerization and reduce distillate (jet and diesel) yield, increasing H₂ consumption per barrel feed converted significantly. Based on the H₂ input to feed mass ratios of 2.7 wt. % and 4.0 wt. % H₂ targeting maximum distillate, and maximum jet, respectively, reported in the literature,^{14 15} total H₂ inputs targeting jet fuel production could be 1.3 wt. % feed (e.g., 801 SCF per barrel for soybean oil) greater than those targeting distillate production. This extra hydrogen for targeting maximum jet fuel yield is expected to be consumed in the hydrocracking/isomerization step, which acts on hydrocarbons that already have been saturated and deoxygenated. Thus, this estimate was applied across feeds, based on their specific gravity, for fuels production targeting jet fuel.

Note also that additional H_2 could be consumed by HEFA processing in ways that are not included in this estimate. For example, with some common HEFA process catalysts, "up to 1-

¹⁴ Pearlson et al., 2013. A techno-economic review of hydroporcessed renewable esters and fatty acids for jet fuel production. *Biofuels Bioproducts & Biorefining* 7: 89–96. DOI: 10,1002/bbb.1378. ¹⁵ Seber et al., 2014. Environmental and economic assessment of producing hydroprocessed jet and diesel fuel from

waste oils and tallow. Biomass & Bioenergy 67: 108-118. Http://dx.doi.org/10.1016/j.biombioe.2014.04.024.

2% sulfiding agent is added to the feed, which generates H_2S by decomposition at the reaction temperature in the presence of hydrogen and keeps the catalyst activity."¹⁶ This could add as much as roughly 30–70 SCFB (1–3%) to total HEFA processing H_2 demand. However, whether or not a particular biorefinery uses a sulfided catalyst, and if so, how much sulfur is added to protect catalyst activity, are unknown in the absence of detailed design or operating data. For these reasons H_2 demand associated with catalyst sulfiding has not been included in the H_2 demand estimate used herein.

Overall, the estimate here appears to be conservative and more likely to underestimate than to overestimate H_2 demand for a particular HEFA process feed and processed fuel product, especially for processing that targets distillate production.

¹⁶ Satyarthi et al. An overview of catalytic conversion of vegetable oils/fats into middle distillates. *Catal. Sci. Technol.* (**2013**) 3:70. DOI: 10.1039/c2cy20415k. <u>See p. 75.</u>

Table A3. Feed-weighted on purpose hydrogen production for U.S. petroleum crude oil refining.

| | Units | Value | Annotation |
|------------------------------|------------------------------------|------------|------------|
| Hydrogen production | Million standard cubic feet/day | 4,201 | а |
| Crude feed rate | Barrels per day | 15,360,289 | b |
| Feed weighted H ₂ | Standard cubic feed/barrel (SCF/b) | 273 | С |

Barrel (b): 42 U.S. gallons

Explanatory notes and data reference.

a. Mean hydrogen production, data reported for 2006–2008 from Karras, 2010.¹ This onpurpose steam reforming production value excludes hydrogen recaptured from petroleum via catalytic naphtha reforming.

b. Data reported for 2006–2008 in Karras, 2010;¹ original data reported by the U.S. Energy Information Administration, as described in Karras, 2010.

c. This mean value for hydrogen production per barrel of crude oil refined is a calculated value. It was derived from dividing hydrogen production (SCF/d) by crude feed rate (b/d). The 2006–2008 period was chosen because it represents the highest hydrogen production per barrel crude feed rates in the 1999–2008 data set reported by Karras, 2010, and represents the period immediately before the U.S. oil shale boom began to reduce the average density of crude feeds, which would be expected to reduce hydrogen demand per barrel refined. This was considered a conservative (high) estimate for comparison with HEFA biofuel refining hydrogen demand for these reasons.

¹ Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential? *Environ. Sci. Technol.* 44(24): 9584–9589. <u>See esp.</u> Supporting Information, Table S1. <u>https://pubs.acs.org/doi/10.1021/es1019965</u>

| Verified and permitted design capacities, converted to MJ | | | | | | | | | |
|---|--------------|--------------------|------------|----------------------|----------------------|--------------|-------------|------------|------|
| ID#: BAAQMD Source ID | | HP: hydrogen plant | | RF: Reformer furnace | | | F: furnace | H: Heater | |
| Refinery | H2 Plant | Owner | ID# | MMSCFD | Ref. | Furnace(s) | ID# | MJ/day | Ref. |
| MPC Martinez | 2 HP | Air Products | S-1030 | 35.0 | а | 2 HP RF | S-1031 | 7,457,260 | а |
| MPC Martinez | 1 HP | MPC | S-1005 | 85.0 | b | 1 HP Selas | S-937 | 18,812,760 | с |
| P66 Rodeo | U 110 | P66 | S-437 | 28.5 | d | U 110 RF | S-438 | 6,330,000 | d |
| P66 Rodeo | U 210 | Air Liquide | S-1 | 120.0 | е | H 210 RF | S-2 | 27,143,040 | е |
| Chevron Richmond | Retired plt. | Chevron | S-4259 | 181.1 | f | F305 | S-4170 | 20,762,400 | f |
| Chevron Richmond | Retired plt. | Chevron | | | | F355 | S-4171 | 20,762,400 | f |
| Chevron Richmond | Retired plt. | Chevron | | | | F320 | S-4156 | 1,071,036 | f |
| Chevron Richmond | Retired plt. | Chevron | | | | F330 | S-4157 | 1,071,036 | f |
| Chevron Richmond | Retired plt. | Chevron | | | | F340 | S-4158 | 1,058,376 | f |
| Chevron Richmond | Trains 1&2 | Praxair | S-4449/50 | 280.0 | f | T1&2 RFs | S-4471/2 | 46,588,800 | f |
| Valero | HP \$1010 | Valero | S-1010 | 164.0 | g | F301/F351 | S-21/22 | 30,631,002 | g |
| Valero | Both HPs | Valero | S1010/1061 | 272.0 | g | F351/F5501 | S-22/S-1061 | 40,129,101 | g |
| PBF/Shell | HP1 DH | PBF(then) | S-1445 | 75.0 | h | F60 RF | S-1505 | 13,926,000 | h |
| PBF/Shell | HP 2 OPCEN | PBF(then) | S-1774 | 43.5 | h | F104 RF | S-1761 | 12,052,320 | h |
| PBF/Shell | HP 3 DC | PBF(then) | S-4160 | 90.0 | h | H101 RF | S-4161 | 23,041,200 | h |
| MPC Martinez | 2 HP | Air Products | S-1030 | 35.0 | а | 2 HP RF | S-1031 | 6,365,997 | i |
| MPC Martinez | 1 HP | MPC | S-1005 | 89.0 | i | 1 HP Selas | S-937 | 11,394,000 | i |
| Chevron Richmond | Trains 1&2 | Praxair | S-4449/50 | 244.0 | f, k | T1&2 RFs | S-4471/2 | 46,588,800 | f, k |
| Valero | HP \$1010 | Valero | S-1010 | 164.0 | I | F301/F351 | S-21/22 | 31,085,498 | I |
| | | | | | | • | | | |
| MPC Martinez | 2 HP | MJ/SCF | 0.2130 | | | MPC Capacit | y wtd. | 0.2187 | |
| MPC Martinez | 1 HP | MJ/SCF | 0.2210 | | | | | | |
| P66 Rodeo | U 110 | MJ/SCF | 0.2220 | | | P66 Capacity | / wtd. | 0.2252 | |
| P66 Rodeo | U 210 | MJ/SCF | 0.2260 | | | | | | |
| Chevron Richmond | Retired plt. | MJ/SCF | 0.2470 | | 11 plant median 0.20 | | 0.2020 | | |
| Chevron Richmond | Trains 1&2 | MJ/SCF | 0.1660 | | | | | | |
| Valero | HP \$1010 | MJ/SCF | 0.1870 | | | | | | |
| Valero | Both HPs | MJ/SCF | 0.1470 | | | | | | |
| PBF/Shell | HP1 DH | MJ/SCF | 0.1860 | | | | | | |
| PBF/Shell | HP 2 OPCEN | MJ/SCF | 0.2770 | | | | | | |
| PBF/Shell | HP 3 DC | MJ/SCF | 0.2560 | | | | | | |
| MPC (note i) | 2 HP | MJ/SCF | 0.2020 | | | | | | |
| MPC (note j) | 1 HP | MJ/SCF | 0.1420 | | | | | | |
| Chevron T1&2 (note k) | | MJ/SCF | 0.1910 | | | | | | |
| Valero S-1010 (note I) | | MJ/SCF | 0.1890 | | | | | | |

Table A4. Combustion Energy Intensity (EI) Data, Bay Area Refinery Hydrogen Plants

Annotated data references:

a. Air Products permit as revised 20 Apr 2016. *Major Facility Review Permit Issued To: Air Products and Chemicals Inc., Facility #B0295, A support facility for Tesoro Refining and Marketing Company, Facility #B2758 & Facility #B2759; 20 Apr 2016. Title V Permit issued by the Bay Area Air Quality Management District: San Francisco, CA. <u>See</u> Contra Costa County, at: https://www.baaqmd.gov/permits/major-facility-review-title-v/title-v-permits*

b. Tesoro (now Marathon) permit as proposed with no change in Oct 2019. *Proposed Renewal "Revision 6" Major Facility Review Permit Issued To: Tesoro Refining and Marketing Company LLC, Facility #B2758 & Facility #B2759;* Title V Permit renewal proposed by the Bay Area Air Quality Management District: San Francisco, CA. <u>See Contra Costa County, at: https://www.baaqmd.gov/permits/major-facility-review-title-v/title-v-permits</u>

c. Appendix B, Table 52 and Data Form X of permit application submitted by Marathon in Oct 2020. *Application for Authority to Construct and Title V Operating Permit Amendment: Martinez Renewable Fuels Project;* 30 Sep 2020. Prepared for Tesoro Refining & Marketing Co. LLC, an indirect, wholly-owned subsidiary of Marathon Petroleum Corp. (Facility #B2758 and #B2759). Ashworth Leininger Group. BARR.

d. Phillips 66 permit as revised 27 Dec 2018. *Major Facility Review Permit Issued To: Phillips 66–San Francisco Refinery, Facility #A0016;* 27 Dec 2018. Title V Permit issued by the Bay Area Air Quality Management District: San Francisco, CA. <u>See Contra Costa County, at: https://www.baaqmd.gov/permits/major-facility-review-title-v/title-v-permits</u>

e. Air Liquide permit as revised 10 Apr 2020. *Major Facility Review Permit Issued To: Air Liquide Large Industries, US LP, Facility #B7419;* 10 Apr 2020. Title V Permit issued by the Bay Area Air Quality Management District: San Francisco, CA. <u>See</u> Contra Costa County, at: <u>https://www.baaqmd.gov/permits/major-facility-review-title-v/title-v-permits</u>

f. Chevron permit revision as proposed by Bay Area Air Quality Management District in Oct 2019; verified daily capacity. *Proposed Revision to Major Facility Review Permit Issued To: Chevron Products Company, Facility #A0010;* Title V Permit revision proposed by the Bay Area Air Quality Management District: San Francisco, CA. <u>See Contra Costa County, at: https://www.baaqmd.gov/permits/major-facility-review-title-v/title-v-permits</u>

g. Valero permit as revised 10 Apr 2015; permitted annual capacity. The "Both HPs" condition applies to both hydrogen plants onsite, and this capacity is based on half of the HP S1010 trains operating when both plants are in service. *Major Facility Review Permit Issued To: Valero Refining Co.–California, Facility #B2626;* 10 Apr 2015. Title V Permit issued by the Bay Area Air Quality Management District: San Francisco, CA. <u>See</u> Solano County, at: <u>https://www.baaqmd.gov/permits/major-facility-review-title-v/title-v-permits</u>

h. PBF (formerly Shell) permit revised 11 Feb 2020. <u>See</u> Condition #18618. The "PBF(then)" notation refers to the reported sale by PBF of one or more of these hydrogen plants to a third-party operator, after the date of this permit revision. *Major Facility Review Permit Issued To: Martinez Refining Company LLC, Facility* #A0011; 11 Feb 2020. Title V Permit issued by the Bay Area Air Quality Management District: San Francisco, CA. <u>See</u> Contra Costa County, at: <u>https://www.baaqmd.gov/permits/major-facility-review-title-v/title-v-permits</u>

i. Appendix B, Table 98 of permit application submitted by Marathon in Oct 2020; this table includes an unverified alternative assumption regarding firing energy; estimate for 90% capacity. <u>See</u> note c for data source reference.

j. Appendix B, Table 87 of permit application submitted by Marathon in Oct 2020; this table includes an unverified alternative assumption regarding firing energy; estimate for 90% capacity. <u>See</u> note c for data source reference.

k. Chevron permit revision as proposed by Bay Area Air Quality Management District in Oct 2019; verified annual capacity. *See* note f for data source reference.

I. Valero permit as revised 10 Apr 2015; permitted daily capacity. The "Both HPs" condition applies to both hydrogen plants onsite, and this capacity is based on half of the HP S1010 trains operating when both plants are in service. *See* note g for data reference.
| | CO ₂ emis | ssions | CI increment | |
|--|----------------------|-------------|---------------------|---------------|
| Process source | (US tons/yr) | (tons/yr) | (kg/b) ^b | ACT App. Ref. |
| SW Stripper Off-gas Thermal Oxidizer | 768 | 697 | 0.04 | Table 6 |
| 2HDS Depent Reboiler F19 | 60,418 | 54,810 | 3,13 | Table 28 |
| 2HDS Charge Heater F20 | 34,291 | 31,108 | 1.78 | Table 30 |
| HDN Reactor A Heater F28 | 10,886 | 9,876 | 0.56 | Table 32 |
| HDN Reactor B Heater F29 | 10,886 | 9,876 | 0.56 | Table 34 |
| HDN Reactor C Heater F30 | 10,886 | 9,876 | 0.56 | Table 36 |
| Hydrocracker Reactor 1 Heater F31 | 10,886 | 9,876 | 0.56 | Table 38 |
| Hydrocracker Reactor 2 Heater F32 | 10,886 | 9,876 | 0.56 | Table 40 |
| Hydrocracker Reactor 3 Heater F33 | 10,886 | 9,876 | 0.56 | Table 42 |
| Hydrocracker Stabilizer Reboiler F34 | 73,481 | 66,661 | 3.80 | Table 44 |
| 3HDS Recycle Gas Heater F55 | 66,949 | 60,735 | 3.47 | Table 48 |
| Delayed Coker Heater #1 F78 ° | 111,578 | 101,222 | 5.78 | Table 50 |
| Hydrogen Plant Heater F37 d | 404,448 | 366,909 | 20.94 | Table 46 |
| No. 1 Hydrogen Plant d | 394,464 | 357,852 | 20.43 | Table 52 |
| Total of CO ₂ sources reported incl | uding hydrogen | production | 62.7 | |
| Excluding hydrogen production | (shaded proces | ss sources) | 21.4 | |

Table A5. Unverified CO₂ potential to emit calculations for a California HEFA project.^a

a. Calculation results for CO₂, still subject to independent public verification when entered, submitted by MPC to the Bay Area Air Quality Management District in support of its proposed HEFA refinery project in Martinez, CA. Data in U.S. tons are as reported; "ACT Ref." refers to the table in Appendix B of this submission for each potential emission source: *Application for Authority to Construct and Title V Operating Permit Amendment: Martinez Renewable Fuels Project;* 30 Sep 2020. Prepared for Tesoro Refining & Marketing Co. LLC, an indirect, wholly-owned subsidiary of Marathon Petroleum Corp. (Facility #B2758 and #B2759). Ashworth Leininger Group. BARR.

b. Carbon intensity increments were calculated as kilograms CO₂ emitted per barrel biomass feedstock capacity (kg/b), given the potential to emit reported and the proposed project biomass feedstock capacity of 48,000 b/d.

c. The Coker heater, not the Coker itself, is proposed to be repurposed for HEFA processing support.

d. These Marathon-reported data represent only one of the two hydrogen plants at the refinery which would be repurposed for HEFA biomass processing by the proposed project, and thus hydrogen plant emissions in Table A5 are not comparable with hydrogen plant emission estimates presented in the main report.

Table A6. Hydrogen-related process hazard incidents that resulted in significant flaring at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020 Part 1–Causal Factors

| Refinery | Start date Causal factor reported-1 | Causal factor reported–2 | Causal factor reported-3 |
|-------------|---|---|---|
| Phillips 66 | 03/11/10 FGRC bypassed to protect it from high H2 in high gas vol. | HCU SD on HRC SD | HRC SD on HCU feed switch |
| Phillips 66 | 04/27/10 FG imbalance worsened by furnace, other SDs on fin-fan leak | HCU SD on H2 feed supply drop | H2P unplanned SD on unreported cause |
| Marathon | 05/13/10 FGRC overloads/insufficiant capacity | HTU SD on fire at its charge pump. | Charge pump fire when bearing fails after valve failure |
| Marathon | 06/13/10 FGRC overloads on gas volume | HTU SD on vapor release from failed valve. | Vapor release on HTU valve failure after valve plugging |
| Marathon | 06/25/10 FGRC overloads on gas/H2 volume | HCU SD on HRC SD | HCU HRC SD during clutch speed controller/switch problem |
| Marathon | 07/20/10 FGRC overloads on excess H2 vented from PSA beds | Hydrogen imbalance; offspec H2 from SU | H2P SU after SD on failed feed gas compressor vibration switch |
| Phillips 66 | 07/20/10 FGRC bypassed to protect it from high H2 in high gas vol. | FGRCs and HRCs SD on sag | Voltage sag (offsite) |
| Marathon | 08/03/10 FGRC overloads on excess H2 vented from PSA beds | Hydrogen imbalance; offspec H2 from SU | H2P SU after SD on high feed gas compressor vibration |
| Phillips 66 | 09/13/10 FGRCs lost/overwhelmed by gas quality and pressure | HCUs, HTU SDs on H2P SD H2 feed loss | H2P SD on fan bearing thermocouple fault |
| Phillips 66 | 09/25/10 FGRC lost on high liquids | H2P feed, liquids blowdown to FGRS | HCU level controller malfunction |
| Marathon | 09/28/10 FGRC SDs on high discharge pressure | HCU SD on abnormal heat in reactor bed | HCU charge pump SD on suspected low lube oil pressure switch |
| Phillips 66 | 10/06/10 HCU PSV lift/failure on upset | HCUs, HTU upsets on H2 loss | H2P SD on stuck PSA valve |
| Phillips 66 | 10/22/10 Steam power plant SD due to H2P SD steam pressure upset | HCU/HTU upsets/SD on H2 & steam loss | H2P SD on power trip due to high temp pump bearing alarm |
| Marathon | 10/26/11 HCU, HTU SDs on H2P SD (loss of H2) | H2P SD on compressor SDs due to off-spec feed after valve failur | r Power trip on failure of aging surge limiter |
| Phillips 66 | 10/27/10 FGRCs left off to blowout plug | HCU upset dumps overpressure gases to blowdown | Hydrate plug in HCU on SU at off-spec-low temperature |
| Marathon | 11/19/10 FGRC overloads on excess H2 vented from PSA beds | Hydrogen imbalance; offspec H2 from SU | H2P SU after SD on PSV release due to boiler failure |
| Marathon | 02/17/11 HCU SD on H2 loss; FGRCs SD on high discharge pressure | H2P SD on fire; regenerator boilover from process upset ignites | H2P feed compressor SD on motor winding short |
| Phillips 66 | 02/21/11 H2Ps upset/SD on high hydrogen sulfide feed | DGA pump SDs (Diethylene Glycol Amine) | Power trip on arcing on bus bar |
| Marathon | 03/31/11 FGRC SDs on high vol., H2 | WGC SDs on high H2 | Partial H2P SD on leak in PSA vent gas line (6 of 12 PSA beds SD) |
| Marathon | 04/25/11 FGRC SDs on high H2 gases | Gas Plant upset on hydrogen, WGC SDs on C-1 carryover liquids | Column C-1 flooding on high lean oil and steam flows |
| Phillips 66 | 06/05/11 HCU depressure on sudden loss of hydrogen | H2P SD on steam pressure loss to PSA | Steam power plant upset on alarm system error, pressure loss |
| Marathon | 06/18/11 H2P SU after unplanned SD | H2P SD on compressor failure the day before | Valves overheating, control logic failure tripped compressor |
| Marathon | 06/27/11 FGRC bypassed on high H2 gases | H2 overload on HCU SD | HCU charge pump SD on unkown cause |
| Marathon | 06/28/11 FGRC SD on high H2 gases | HTU SD on heavy gas oil piping leak | Investigation suggested corrosion caused piping pinhole leak |
| Phillips 66 | 07/23/11 FGRC SD due to voltage sag, HCU and other unit upsets | HCU upset on H2 makeup compressor SD due to voltage sag | Voltage sag on transformer relay trip offsite |
| Phillips 66 | 12/05/11 FGRC loss on gas quality (offspec H2P gases dumped to FG) | Unit upsets on H2 loss | H2P SD on weld failure on ID Fan Jack Shaft |
| Phillips 66 | 01/16/12 FGRCs out (recirculation to protect from H2 excess) | H2P SU <sd 1="" day="" earlier<="" td=""><td>H2P SD on instrument control computer hardware failure</td></sd> | H2P SD on instrument control computer hardware failure |
| Phillips 66 | 01/18/12 FG imbalance; HCU feed to H2P among others | H2P cuts HCU feed to protect the H2P Feed Gas Compressor | H2P feed contaminated by liquids in gas feed due to HCU upset |
| Marathon | 03/14/12 HCU SD on instrument failure | H2Ps SD on instrument failure | Inst air loss on pipe failure initiated by construction (backhoe) |
| Phillips 66 | 03/26/12 FG imbalance; liquids in HCU feed to H2P | H2P SD on offspec HCU feed to H2P | Liquids in H2P feed from HCU; poss. heat exchanger malfunction |
| Marathon | 04/11/12 Gas dumped to flare due to volume, H2, catalyst poison hazard | HTU upset on H2P SD (3HDS pulled feed and went into circulatio |) H2P SD on valve failure (solenoid valve) |
| Phillips 66 | 05/23/12 FGRCS overloads/insufficiant capacity | Other HCU SD for maintenance: excacerbated FG imbalance | HCU malfunctions: U240 Plt 3 SD on leak in fin fan cooler |
| Phillips 66 | 07/24/12 High H2S gas leak flared (300-400 MSCFD unscrubbed gas) | Hazardous system repair planning took several weeks | HCU emergency relief valve leak |
| Phillips 66 | 07/27/12 High H2S gas leak flared (300-400 MSCFD unscrubbed gas) | Hazardous system repair planning took several weeks | HCU emergency relief valve leak |
| Phillips 66 | 08/01/12 High H2S gas leak flared (300-400 MSCFD unscrubbed gas) | Hazardous system repair planning took several weeks | HCU emergency relief valve leak |
| Phillips 66 | 08/04/12 High H2S gas leak flared (300-400 MSCFD unscrubbed gas) | Hazardous system repair planning took several weeks | HCU emergency relief valve leak |
| Marathon | 08/21/12 FGRC SD on low SG vent gas | Second HMC, FGRC, out for maintenance during incident | HTU SD on HMC SD due to vibration from mechanical flaw |
| Phillips 66 | 08/24/12 HCU depressured to flare; FGRC loss on hydrogen sulfide alarms | H2P cuts HCU feed to protect the H2P Feed Gas Compressor | HCU SD on false high-temperature alarm |
| Phillips 66 | 08/27/12 SU in parts of HCU complex suspected in off-spec H2P feed | H2P cuts feed from HCU due to hydrogen sulfide poisoning of fee | Contamination of H2P feed; CO2 poisoned off gas scrubbing |
| Phillips 66 | 09/09/12 HCU and HTU processing SDs as they cut (removed) feed | H2P SD caused HCU and HTU upsets on sudden H2 loss | U110 H2P SD due to a ruptured boiler feed water line |
| Phillips 66 | 09/10/12 PRV lift and fire on H2 overpressure (U110 hydrogen header) | Overpressure at H2P U110 caused by H2P U210 H2P SU | H2P U210 SU followed its SD on ruptured boiler water feed line |
| Phillips 66 | 10/04/12 HCU SD on reactor hotspot upon loss of H2 compressor capacity | HCU H2 makeup compressor malfunction and PRV lift | HCU H2 makeup compressor lube oil injection system failure |
| Phillips 66 | 01/08/13 FGRC G-503 SD for protection from H2 in HCU depressure gases | HCU SD | Cooling failure (U246 forced-draft fan) |
| Marathon | 01/11/13 FGRCs overwhelmed by H2P, HCU, HTU, naphtha unit SDs | HCU, HTU (3HDS) SDs on H2 supply loss | 1H2P SD on cracked, overheated and "glowing" H2 piping |
| | | | |

Table A6. Hydrogen-related process hazard incidents that resulted in significant flaring at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020 continued

FGRS: flare gas recovery system H2: hydrogen H2P: hydrogen plant HCU: hydrocracking unit HRC: hydrogen recycle compresson FGRC: flare gas recovery compressor Part 1—Causal Factors KEY FG: fuel gas HTU: hvdrotrea

Table A6. Hydrogen-related process hazard incidents that resulted in significant flaring at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020 continued Part 1—Causal Factors

FG: fuel gas FGRC: flare gas recovery compressor FGRS: flare gas recovery system H2: hydrogen H2P: hydrogen plant HCU: hydrocracking unit HRC: hydrogen recycle compressor HTU: hydrotreating unit N: nitrogen PRV: pressure swing absorber PSV: pressure safety valve SD: shutdown SU: startup WGC: wet gas compressor KEY

| Refinery | Start date Causal factor reported-1 | Causal factor reported-2 | Causal factor reported–3 |
|-------------|--|---|--|
| Marathon | 06/12/18 H2P SD on PSV release to air | Boiler feed water PSV failure | PSV spring was found broken due to an unreported cause |
| Phillips 66 | 04/23/19 H2P SD on a safety system trip | PSA upset in the H2P | The PSA upset was caused by a faulty PSA valve component |
| Marathon | 05/13/19 HCU and H2P SDs cause upset & SD of HTU, naphtha unit | HCU and H2P SDs on partial power outage | Partial outage; substation breaker trip on overvoltage |
| Marathon | 05/16/19 FGRC overloads; insufficient capacity | HCU SD to stop seal oil leak from failed PSV on its Stage 2 HRC | TPSV had valve seats corrosion; possible valve spring weakening |
| Marathon | 06/18/19 H2P upset rapidly depressurizes PSAs in H2P to flare | High PSAs pressure difference with hydrogen header | H2P control system malfunction |
| Marathon | 10/14/19 HTU, HCU, H2P, other unit SDs | HTU, HCU, H2P compressors trip on high vibration | Earthquake centered near Pleasant Hill caused the high vibration |
| Phillips 66 | 11/11/19 Loss of hydrogen from H2P forces HTU SD | Sudden heater fuel loss trips H2P PSAs | A valve failed on a broken spring, likely due to metal fatigue |
| Phillips 66 | 12/03/19 FG imbalance | Refinery fuel gas backed out of steam turbines due to sulfur | HCU catalyst sulfiding agent contaminates fuel gas |
| Phillips 66 | 12/11/19 Refinery sulfur recovery unit upsets and SDs | Sulfur unit psets and SDs caused by HCU control failure | HCU furnace level indicator malfunction |
| Marathon | 02/07/20 HTU SD on HTU recycle compressor SD | HTU recycle compressor SD on loss of lube oil | Lube pump switch unprotected from inadvertent activation |
| Phillips 66 | 03/05/20 HCU SD on HCU makeup compressor SD | HCU makeup compressor tripped on voltage sag | Voltage sag occurred in third-party power supply |
| Phillips 66 | 10/16/20 Hydro-conversion unit upsets on sudden H2 loss | H2P SD on PSA upset & high pressure trip | PSA upset, pressur trip, on valve that was slow to close |
| Phillips 66 | 10/19/20 H2P SU after unplanned SD | HCU/HTU SU/ramp-up after unplanned SDs/upsets | SU after SD due to PSA valve fault on 10/16/20 |
| Phillips 66 | 10/25/20 FGRCs bypassed on high H2, N, depressurization volume | Excess H2/N in depressure & purge gases | Unplanned HCU maintenance SD related to 10/16/20 incident |
| | | | |

Table A6. Hydrogen-related process hazard incidents that resulted in significant flaring at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020 continued Part 2—Vent Gas Flared: volumes in standard cubic feet (SCF)

| Refinery | Start date | SCF flared | Refinery | Start date | SCF flared | Refinery | Start date | SCF flared | Refinery | Start date | SCF flared |
|-------------|------------|------------|-------------|------------|--------------|-------------|------------|------------|-------------|------------|------------|
| Phillips 66 | 03/11/10 | | Phillips 66 | 01/16/12 | 1,628,000 | Marathon | 01/02/14 | 9,530,000 | Phillips 66 | 02/10/16 | 2,302,000 |
| Phillips 66 | 04/27/10 | 2,656,000 | Phillips 66 | 01/18/12 | 11,939,000 | Marathon | 01/14/14 | 16,510,000 | Phillips 66 | 03/12/16 | 1,509,000 |
| Marathon | 05/13/10 | 810,000 | Marathon | 03/14/12 | 17,900,000 | Marathon | 02/27/14 | 1,980,000 | Phillips 66 | 03/14/16 | 4,806,000 |
| Marathon | 06/13/10 | 780,000 | Phillips 66 | 03/26/12 | 4,028,080 | Phillips 66 | 06/01/14 | 1,504,000 | Marathon | 08/31/16 | 3,140,000 |
| Marathon | 06/25/10 | 4,960,000 | Marathon | 04/11/12 | 3,420,000 | Marathon | 07/22/14 | 1,300,000 | Marathon | 11/26/16 | 850,000 |
| Marathon | 07/20/10 | 670,000 | Phillips 66 | 05/23/12 | 8,970,000 | Phillips 66 | 09/25/14 | 320,000 | Marathon | 01/18/17 | 12,400,000 |
| Phillips 66 | 07/20/10 | 1,220,000 | Phillips 66 | 07/24/12 | 2,795,000 | Phillips 66 | 10/23/14 | 2,264,000 | Phillips 66 | 01/22/17 | 1,309,000 |
| Marathon | 08/03/10 | 680,000 | Phillips 66 | 07/27/12 | 4,028,080 | Phillips 66 | 09/30/14 | 1,510,000 | Phillips 66 | 07/08/17 | 545,017 |
| Phillips 66 | 09/13/10 | 600,000 | Phillips 66 | 08/01/12 | 3,428,000 | Marathon | 12/06/14 | 1,220,000 | Marathon | 08/23/17 | 310,000 |
| Phillips 66 | 09/25/10 | 354,000 | Phillips 66 | 08/04/12 | 2,170,000 | Marathon | 12/28/14 | 1,290,000 | Marathon | 04/06/18 | 970,000 |
| Marathon | 09/28/10 | 5,670,000 | Marathon | 08/21/12 | 000'069 | Phillips 66 | 01/25/15 | 14,247,000 | Marathon | 06/12/18 | 1,090,000 |
| Phillips 66 | 10/06/10 | 1,815,000 | Phillips 66 | 08/24/12 | 18,470,000 | Phillips 66 | 02/04/15 | 643,000 | Phillips 66 | 04/23/19 | 1,048,000 |
| Phillips 66 | 10/22/10 | 12,657,000 | Phillips 66 | 08/27/12 | 2,266,000 | Phillips 66 | 02/14/15 | 1,118,000 | Marathon | 05/13/19 | 1,520,000 |
| Marathon | 10/26/11 | 20,400,000 | Phillips 66 | 09/09/12 | Not reported | Marathon | 04/17/15 | 1,370,000 | Marathon | 05/16/19 | 1,520,000 |
| Phillips 66 | 10/27/10 | 2,997,000 | Phillips 66 | 09/10/12 | 5,628,000 | Phillips 66 | 05/18/15 | 5,676,000 | Marathon | 06/18/19 | 502,000 |
| Marathon | 11/19/10 | 540,000 | Phillips 66 | 10/04/12 | 7,111,000 | Marathon | 05/19/15 | 2,020,000 | Marathon | 10/14/19 | 2,100,000 |
| Marathon | 02/17/11 | 5,860,000 | Phillips 66 | 01/08/13 | 227,000 | Marathon | 07/28/15 | 8,390,000 | Phillips 66 | 11/11/19 | 1,965,000 |
| Phillips 66 | 02/21/11 | 7,652,000 | Marathon | 01/11/13 | 42,750,000 | Marathon | 08/06/15 | 3,470,000 | Phillips 66 | 12/03/19 | 3,200,000 |
| Marathon | 03/31/11 | 2,330,000 | Marathon | 02/02/13 | 57,620,000 | Marathon | 08/08/15 | 720,000 | Phillips 66 | 12/11/19 | 513,000 |
| Marathon | 04/25/11 | 1,270,000 | Marathon | 03/05/13 | 1,150,000 | Marathon | 09/12/15 | 24,580,000 | Marathon | 02/07/20 | 600,000 |
| Phillips 66 | 06/05/11 | 1,681,000 | Marathon | 03/18/13 | 1,480,000 | Marathon | 09/22/15 | 2,160,000 | Phillips 66 | 03/05/20 | 208,000 |
| Marathon | 06/18/11 | 1,850,000 | Phillips 66 | 04/11/13 | 1,167,000 | Phillips 66 | 10/03/15 | 1,251,700 | Phillips 66 | 10/16/20 | 4,226,000 |
| Marathon | 06/27/11 | 2,870,000 | Phillips 66 | 06/10/13 | 1,818,000 | Marathon | 10/29/15 | 23,200,000 | Phillips 66 | 10/19/20 | 531,000 |
| Marathon | 06/28/11 | 51,700,000 | Phillips 66 | 07/03/13 | 7,767,000 | Phillips 66 | 11/02/15 | 29,470,000 | Phillips 66 | 10/25/20 | 823,000 |
| Phillips 66 | 07/23/11 | 422,000 | Marathon | 09/09/13 | 30,050,000 | Phillips 66 | 01/17/16 | 13,188,000 | | | |
| Phillips 66 | 12/05/11 | 230,000 | Marathon | 11/15/13 | 7,840,000 | Marathon | 01/21/16 | 24,400,000 | | | |

Explanatory note and reference for Table A6.

Data were taken from reports submitted by refiners pursuant to Bay Area Air Quality Management District regulations, §12-12-046, which provides:

- 12-12-406 Determination and Reporting of Cause: The owner or operator of a flare subject to this rule shall submit a report to the APCO within 60 days following the end of the month in which a reportable flaring even occurs. The report shall include, but is not limited to, the following:
 - 406.1 The results of an investigation to determine the primary cause and contributing factors of the flaring event.
 - 406.2 Any prevention measures that were considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented.
 - 406.3 If appropriate, an explanation of why the flaring is consistent with an approved FMP.
 - 406.4 Where applicable, an explanation of why the flaring was an emergency and necessary to prevent an accident, hazard or release of vent gas to the atmosphere or where, due to a regulatory mandate to vent to a flare, it cannot be recovered, treated and used as fuel gas at the refinery.
 - 406.5 The volume of vent gas flared, the calculated methane, non-methane hydrocarbon and sulfur dioxide emissions associated with the reportable flaring event.

These reports are available from the Bay Area Air Quality Management District by request and at <u>https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports.</u>

Table A7. Data and Methodological Details Supporting Chart 3 [Combustion fuels additive potential of HEFA diesel and jet production in California] and Chart 4 [Potential growth in hydrogen demand for HEFA production in California and fuel cell electric vehicle (FCEV) transportation in U.S. western states to 2025 and 2045].

| | Survival Rate | (SR)/ years | Age Distribut | ion (AD) | Turn Over TC |) %/yr | |
|----------|---------------|-------------|---------------|----------|--------------|----------|----------------|
| Age (yr) | LD Cars | LD Trucks | Cars | Trucks | By vintage | Total LD | |
| 0 | 1.000 | 1.000 | 7.1% | 6.5% | 0.00% | 0.00% | |
| 1 | 0.997 | 0.991 | 5.9% | 5.1% | 0.02% | 0.02% | |
| 2 | 0.994 | 0.982 | 4.6% | 5.2% | 0.04% | 0.07% | |
| 3 | 0.991 | 0.973 | 4.7% | 4.0% | 0.06% | 0.13% | |
| 4 | 0.984 | 0.960 | 4.2% | 3.2% | 0.08% | 0.21% | |
| 5 | 0.974 | 0.941 | 5.6% | 5.6% | 0.19% | 0.40% | |
| 6 | 0.961 | 0.919 | 6.1% | 6.1% | 0.30% | 0.70% | |
| 7 | 0.942 | 0.891 | 5.9% | 6.1% | 0.42% | 1.13% | |
| 8 | 0.920 | 0.859 | 6.0% | 6.1% | 0.58% | 1.70% | |
| 9 | 0.893 | 0.823 | 5.3% | 6.4% | 0.71% | 2.41% | |
| 10 | 0.862 | 0.784 | 5.6% | 5.8% | 0.89% | 3.30% | |
| 11 | 0.826 | 0.741 | 5.5% | 5.5% | 1.07% | 4.38% | |
| 12 | 0.788 | 0.697 | 5.1% | 4.9% | 1.18% | 5.56% | 11.85 mean age |
| 13 | 0.718 | 0.651 | 5.3% | 4.6% | 1.52% | 7.08% | |
| 14 | 0.613 | 0.605 | 4.2% | 4.2% | 1.63% | 8.72% | |
| 15 | 0.510 | 0.553 | 1.1% | 1.2% | 0.54% | 9.25% | |
| 16 | 0.415 | 0.502 | 1.1% | 1.2% | 0.63% | 9.89% | |
| 17 | 0.332 | 0.453 | 1.1% | 1.2% | 0.72% | 10.60% | |
| 18 | 0.261 | 0.407 | 1.1% | 1.2% | 0.79% | 11.39% | |
| 19 | 0.203 | 0.364 | 1.1% | 1.2% | 0.85% | 12.24% | |
| 20 | 0.157 | 0.324 | 1.1% | 1.2% | 0.90% | 13.13% | |
| 21 | 0.120 | 0.288 | 1.1% | 1.2% | 0.94% | 14.07% | |
| 22 | 0.092 | 0.255 | 1.1% | 1.2% | 0.97% | 15.05% | |
| 23 | 0.070 | 0.225 | 1.1% | 1.2% | 1.00% | 16.05% | |
| 24 | 0.053 | 0.198 | 1.1% | 1.2% | 1.02% | 17.07% | |
| 25 | 0.040 | 0.174 | 1.1% | 1.2% | 1.04% | 18.11% | |
| 26 | 0.030 | 0.153 | 1.1% | 1.2% | 1.05% | 19.16% | |
| 27 | 0.023 | 0.133 | 1.1% | 1.2% | 1.07% | 20.23% | |
| 28 | 0.013 | 0.117 | 1.1% | 1.2% | 1.08% | 21.31% | |
| 29 | 0.010 | 0.102 | 1.1% | 1.2% | 1.09% | 22.39% | |
| 30 | 0.007 | 0.089 | 1.1% | 1.2% | 1.09% | 23.49% | |
| 31 | 0.002 | 0.027 | 1.1% | 1.2% | 1.12% | 24.60% | |

Table A7a. Stock Turnover, U.S. Light Duty Vehicles, Estimate Calculation Data.*

* Survival rate (SR), age distribution (AD), and mean age data were taken from the U.S. Department of Energy.¹ Stock turnover (TO) was calculated from those data assuming that passenger cars comprise 75% of light duty vehicles and an even age distribution for light duty vehicles 15–31 years old. TO at mean age was calculated at 5.56% per year, as shown.

| | First Quarter (weeks 1–13) | Second Quarter (weeks 14–26) | Third Quarter (weeks 27–39) | Fourth Quarter (weeks 40–52) |
|---------------|-------------------------------|---------------------------------|--------------------------------|------------------------------|
| Minimum ratio | 0.441 | 0.437 | 0.481 | 0.422 |
| Mean ratio | 0.602 | 0.588 | 0.613 | 0.608 |
| Median ratio | 0.600 | 0.592 | 0.614 | 0.615 |
| Maximum ratio | 0.759 | 0.683 | 0.757 | 0.756 |

Table A7b. California refinery distillate/gasoline yield ratios, 1 Jan 2010–20 Mar 2020.*

* Distillate, here, includes distillate-diesel and kerosene jet fuel. Data were taken from weekly statewide totals reported by the California Energy Commission.² The 1 Jan 2010 through 20 Mar 2020 data set includes 130 weekly samples per quarter, except for the first quarter (142 weeks up to the first 2020 COVID-19 lockdown). The median distillate/gasoline ratio was highest in the fourth quarter, consistent with industry practice to shut down gasoline production units for needed or mandatory maintenance then, while gasoline demand is lowest. Distillate fuel demand may be similar or higher at this time due to freight and shipping energy needs and holiday air travel. For these reasons, fourth quarter data were judged to support the most reliable and conservative estimate of sustainable distillate production in the event of permanent decline in gasoline demand and production. Given that recurrent refinery fires, explosions and inventory buffers affect weekly refining rates, central tendency was judged more representative of responses to permanent change in gasoline refining rate. The divergence of distributions across quarters for maxima and minima, from those for central tendency (*see* table), also supports this judgment. The median ratio (0.615) was judged to represent the central tendency of the data more reliably than the mean based on evidence that distillate/gasoline production variability is unlikely to be evenly distributed over time. This ratio (0.615) also was judged conservative (high) in a terminal gasoline decline scenario because as straight-run gasoline storage fills up, reduced crude runs would reduce petroleum distillate hydro-conversion feeds as well.

Table A7c. Hydrogen and fuels production and capacity calculation data.

| HEFA scenario 2024 California petroleum refinery hydrogen capacity (MMSCFD) a | 1,107 |
|---|-------|
| Drop-in biomass distillate imports to California, 2017–2019 mean (MM gallons/day) b | 0.986 |
| Drop-in biomass distillate production in Calif., 2017–2019 mean (MM gallons/day) ^b | 0.073 |
| Drop-in distillate capacity of planned California projects, 2021 (MM gallons/day) $^{\circ}$ | 0.630 |
| Drop-in distillate capacity of planned California projects, 2022 (MM gallons/day) $^{\circ}$ | 1.411 |
| Drop-in distillate capacity of planned California projects, 2024 (MM gallons/day) d | 5.710 |
| Hydrogen demand for planned California projects at capacity, 2024 (MMSCFD) ^d | 373.0 |
| Phillips 66 Rodeo project portion, 2024 hydrogen demand (MMSCFD) | 177.6 |
| Marathon Martinez project portion, 2024 hydrogen demand (MMSCFD) | 106.6 |
| Hydrogen demand for planned California projects at capacity, 2035 (MMSCFD) d | 429.9 |
| Phillips 66 Rodeo project portion, 2035 hydrogen demand (MMSCFD) | 204.7 |
| Marathon Martinez project portion, 2035 hydrogen demand (MMSCFD) | 122.8 |
| California petroleum refinery gasoline production in 2019 (MM gal/day) ^e | 43.68 |
| California petroleum refinery gasoline production in 2020 (MM gal/day) e | 37.54 |
| California petroleum refinery distillate-diesel & jet production in 2019 (MM gal/day) e | 27.57 |
| California petroleum refinery distillate-diesel & jet production in 2020 (MM gal/day) e | 20.15 |

a. Assumes proposed HEFA conversions are built and thus excludes hydrogen production capacity at the Phillips 66 Rodeo, Marathon Martinez, AltAir Paramount and Global Clean Energy Bakersfield refineries. Data from U.S. Energy Information Administration.³

b. Data from LCFS Dashboard; California Air Resources Board: Sacramento, CA.4

c. Assumes full implementation of the 0.630 MM gal/day GCE Bakersfield project in 2021⁵ and the proposed Marathon Martinez project 0.773 MM gal/day first phase in 2022⁶ at a feed-to-fuel conversion efficiency for distillates (diesel and jet fuel) of 0.8.

d. Assumes implementation of the Phillips 66 Rodeo,⁷ Marathon Martinez,⁵ AltAir Paramount,⁸ and GCE Bakersfield⁶ projects at a feed-to-fuel conversion efficiency for distillates (diesel and jet fuel) of 0.8. Hydrogen production based on operation at full feed capacities of each plant. H₂ in 2024 based on processing targeting diesel, a jet-to-diesel product ratio of 1:5.33, and the yield-weighted feed blend including 0% fish oil from Table A1. H₂ in 2035 based on a jet fuel-to-diesel processing targets ratio of 64% to 36%, a jet-to-diesel product ratio of 1:2, and the yield-weighted feed blend including 25% fish oil from Table A1. See section A7f below for details of feedstock and product slate drivers from 2024–2035. Phillips 66 and Marathon project feed capacities are 80,000 b/d⁷ and 48,000 b/d,⁵ respectively.

e. Data were taken from the California Energy Commission Fuel Watch.²

| | Stock turnover | Gasoline production | Distillate to | Distillate production |
|------|----------------|---------------------|----------------|-----------------------|
| Year | (%/year) | (MM gal/day) | gasoline ratio | (MM gal/day) |
| 2019 | - | 43.680 | _ | 27.572 |
| 2020 | - | 37.541 | — | 20.154 |
| 2021 | 5.56% | 43.680 | 0.615 | 26.863 |
| 2022 | 5.56% | 41.251 | 0.615 | 25.370 |
| 2023 | 5.56% | 38.958 | 0.615 | 23.959 |
| 2024 | 5.56% | 36.792 | 0.615 | 22.627 |
| 2025 | 5.56% | 34.746 | 0.615 | 21.369 |
| 2026 | 5.56% | 32.814 | 0.615 | 20.181 |
| 2027 | 5.56% | 30.990 | 0.615 | 19.059 |
| 2028 | 5.56% | 29.267 | 0.615 | 17.999 |
| 2029 | 5.56% | 27.640 | 0.615 | 16.998 |
| 2030 | 5.56% | 26.103 | 0.615 | 16.053 |
| 2031 | 5.56% | 24.651 | 0.615 | 15.161 |
| 2032 | 5.56% | 23.281 | 0.615 | 14.318 |
| 2033 | 5.56% | 21.986 | 0.615 | 13.522 |
| 2034 | 5.56% | 20.764 | 0.615 | 12.770 |
| 2035 | 5.56% | 19.609 | 0.615 | 12.060 |
| 2036 | 5.56% | 18.519 | 0.615 | 11.389 |
| 2037 | 5.56% | 17.490 | 0.615 | 10.756 |
| 2038 | 5.56% | 16.517 | 0.615 | 10.158 |
| 2039 | 5.56% | 15.599 | 0.615 | 9.593 |
| 2040 | 5.56% | 14.731 | 0.615 | 9.060 |
| 2041 | 5.56% | 13.912 | 0.615 | 8.556 |
| 2042 | 5.56% | 13.139 | 0.615 | 8.080 |
| 2043 | 5.56% | 12.408 | 0.615 | 7.631 |
| 2044 | 5.56% | 11.718 | 0.615 | 7.207 |
| 2045 | 5.56% | 11.067 | 0.615 | 6.806 |
| 2046 | 5.56% | 10.452 | 0.615 | 6.428 |
| 2047 | 5.56% | 9.870 | 0.615 | 6.070 |
| 2048 | 5.56% | 9.322 | 0.615 | 5.733 |
| 2049 | 5.56% | 8.803 | 0.615 | 5.414 |
| 2050 | 5.56% | 8.314 | 0.615 | 5.113 |

Table A7d. Potential petroleum distillates trajectory*

* Gasoline production fell from 2019 to 2020^2 and in this scenario forecast, is conservatively assumed to rebound fully in 2021. Then electric vehicles would begin to replace gasoline at the stock turnover rate from Table A7a (5.56%/year) and gasoline production declines at that rate. At the distillate to gasoline production ratio from Table A7b (0.615) the declining gasoline production cuts distillate production. These calculation data and methods are consistent with the petroleum diesel and jet fuel trajectory in the HEFA scenario forecast described and supported in Chapter 4 and Chart 4 of the main report.

Note that the stock turnover rather than solely state policy (Table A7a), and EV-less-expensivethan-gasoline (Chapter 4) drivers of gasoline phaseout in this scenario embed an assumption which differs from recent past conditions. Cheaper EVs replace gasoline everywhere in this scenario. Unlike the past local demand decline refiners responded to by increasing exports,⁹ they could not export their way out of this potential scenario.

| | Hydrogen capacity repurposed | | New HEFA Production | | |
|------|------------------------------|----------|---------------------------|------------|--|
| Year | (% of 2019) | (MMSCFD) | (gal/SCF H ₂) | (MM gal/d) | |
| 2019 | 0.0% | 0 | 0.0000 | | |
| 2020 | 0.0% | 0 | 0.0000 | | |
| 2021 | 0.0% | 0 | 0.0000 | | |
| 2022 | 5.6% | 62 | 0.0000 | | |
| 2023 | 10.8% | 120 | 0.0000 | | |
| 2024 | 15.8% | 175 | 0.0153 | | |
| 2025 | 20.5% | 226 | 0.0150 | | |
| 2026 | 24.9% | 275 | 0.0148 | 3.26 | |
| 2027 | 29.1% | 322 | 0.0146 | 3.75 | |
| 2028 | 33.0% | 365 | 0.0143 | 4.19 | |
| 2029 | 36.7% | 407 | 0.0141 | 4.58 | |
| 2030 | 40.2% | 445 | 0.0139 | 4.94 | |
| 2031 | 43.6% | 482 | 0.0136 | 5.27 | |
| 2032 | 46.7% | 517 | 0.0134 | 5.56 | |
| 2033 | 49.7% | 550 | 0.0132 | 5.82 | |
| 2034 | 52.5% | 581 | 0.0130 | 6.05 | |
| 2035 | 55.1% | 610 | 0.0128 | 6.26 | |
| 2036 | 57.6% | 638 | 0.0128 | 6.54 | |
| 2037 | 60.0% | 664 | 0.0128 | 6.81 | |
| 2038 | 62.2% | 688 | 0.0128 | 7.07 | |
| 2039 | 64.3% | 712 | 0.0128 | 7.30 | |
| 2040 | 66.3% | 734 | 0.0128 | 7.53 | |
| 2041 | 68.1% | 754 | 0.0128 | 7.74 | |
| 2042 | 69.9% | 774 | 0.0128 | 7.94 | |
| 2043 | 71.6% | 793 | 0.0128 | 8.13 | |
| 2044 | 73.2% | 810 | 0.0128 | 8.31 | |
| 2045 | 74.7% | 827 | 0.0128 | 8.48 | |
| 2046 | 76.1% | 842 | 0.0128 | 8.64 | |
| 2047 | 77.4% | 857 | 0.0128 | 8.79 | |
| 2048 | 78.7% | 871 | 0.0128 | 8.94 | |
| 2049 | 79.8% | 884 | 0.0128 | 9.07 | |
| 2050 | 81.0% | 896 | 0.0128 | 9.20 | |

Table A7e. Potential hydrogen repurposing for new HEFA fuels trajectory*

* In this scenario forecast, continued from Table A7d, petroleum refining hydrogen production assets are idled along with petroleum fuels production at the percentages of 2019 rates based on fuel volume shown in A7d. Those otherwise stranded hydrogen assets are repurposed for new HEFA production at volumes calculated by applying the percentages shown in this table to the petroleum refining hydrogen capacity in Table A7c. The gallons of HEFA fuel per SCF H₂ shown and the repurposed hydrogen capacities determine the HEFA distillate fuel production volume trajectory from 2026–2050. Gallons of fuel production capacity/SCF H₂ decrease proportionately from 2024 (0.0153) to 2035 (0.0128) as HEFA feedstock and jet fuel demand increase (see note A7f below for feed and product slate drivers of the gal./SCF trajectory). The new HEFA capacity, additional to currently proposed projects, would start to capture left-over unmet demand for declining petroleum diesel and jet fuel around 2026. This plausible further HEFA growth would add to that from existing and currently planned in-state HEFA capacity

(Table A7c), as described in the main report. The data and methods description above details the calculations for this scenario forecast, as referenced in charts 4 and 5; for a complete description of the context and support for this plausible scenario, see the main report, *esp*. Chapter 4.

A7f. Notes on feedstock and product slate trajectory assumptions

Gallons of fuel production capacity/SCF H₂ decrease proportionately from 2024 (0.0153) to 2035 (0.0128) as HEFA feedstock and jet fuel demand increase during this 2024–2035 period. Average feedstock blends are assumed to shift, in the Table A7d/e scenario, from yield-weighted blends with 0–25% fish oil (Table A1) with increasing demand on limited lipid biomass. At the same time the jet-to-diesel production ratio increases, with increasing replacement of petroleum jet fuel. This shift from 1:5.33 to 1:2 gallons jet per gallon diesel product results from an estimated change in the processing targets, from 100% diesel-targeted processing to an average maximum diesel/maximum jet fuel processing target of 64%/36%.

The jet fuel increase to one gallon per three gallons diesel was based on two assumptions. First, that replacement of petroleum jet fuel will be given priority as there are few if any other options, as compared with petroleum diesel replacement, which can be accomplished by FCEV, BEV, and/or cellulosic biomass-derived diesel production as well as by HEFA diesel. This assumption is consistent with the priority-ranked hierarchies described by Austin et al. (2021)¹⁰ and Ueckerdt et al. (2021).¹¹ Second, replacement of petroleum jet fuel by HEFA-produced kerosene is limited to half of total jet fuel by a maximum blending limit of 50%.¹² This blend limit was assumed to remain in place through the forecast period.

Both the feedstock shift and the process target shift increase H₂ demand per barrel processed. The combined effect increases hydrogen demand per barrel feed from 2,220–2,559 SCF/b (compare processing target breakdown with jet and diesel processing targets data in Table A1). Since the higher rate of hydrogen consumption per barrel feed translates to a lower rate of HEFA fuel production growth per SCF hydrogen capacity repurposed, gallons of new HEFA production per SCF hydrogen decline, as shown during 2024–2035 in Chart A7e. The overall effect of these details in the trajectory analysis results in a more conservative HEFA capacity growth estimate for this scenario.

| Estimate Calculation Data for Potential CO ₂ e Emissions Associated with HEFA Distillate (Diesel |
|---|
| and Jet Fuel) Biofuels Produced and Used in California in 2050—Table A7 Scenario. |

| Mt: Megaton; 1 million metric tons Bn gal: Billion gallons | kg: | kilogram |
|--|-------|-------------|
| Volume | | |
| HEFA distillates refined and burned in CA (a) | 5.47 | Bn. Gal./yr |
| CA per capita share of lipids biomass for food and fuel (b) | 0.58 | Bn. Gal./yr |
| Excess lipids shifted to CA for HEFA biofuel (c) | 4.89 | Bn. Gal./yr |
| Distillate Fuels Mix | | |
| Diesel percentage of HEFA distillates refined and burned (d) | 66.7% | |
| Jet fuel percentage of HEFA distillated refined and burned (d) | 33.3% | |
| Fuel Chain Carbon Intensity (CI) | | |
| HEFA diesel CI, kg CO2e/gal. (e) | 7.62 | kg CO2e/gal |
| HEFA jet fuel CI, kg CO2e/gal. (e) | 8.06 | kg CO2e/gal |
| Petroleum diesel CI, kg CO2e/gal. (e) | 13.50 | kg CO2e/gal |
| Petroleum jet fuel CI, kg CO2e/gal. (e) | 11.29 | kg CO2e/gal |
| Emissions (millions of metric tons CO2e) | | |
| Emissions from CA HEFA use of per capita share of lipids | 4.50 | Mt/yr |
| Emissions from excess CA HEFA use shifted to CA (Mt/y) | 37.98 | Mt/yr |
| Emissions shift to other states and nations, Mt/y (f) | 24.44 | Mt/yr |
| Total emissions (Mt/y) (f) | 66.92 | Mt/yr |

a. Potential 2050 HEFA diesel and jet fuel refinery production and use in California from tables A7c and A7e, including planned California refinery conversion projects operating at 2035 rates from Table A7c.

b. Statewide per capita share of U.S. farm yield for all uses of lipids used in part for biofuels during Oct 2016–Sep 2020 from U.S. Dept. of Agriculture *Oil Crops Data: Yearbook Tables;* tables 5, 20, 26 and 33;¹³ and for livestock fats and used ("waste") cooking oil, from U.S. Department of Energy *Billion-Ton Update* (2011).¹⁴ *See* also Table 1 in the main report. Converted to distillate volume at specific gravity of 0.914 and feed-to-distillate fuel ratio of 0.809 (after Pearlson, for the jet:diesel process targets ratio for a jet:diesel 1:2 products slate. Importantly, these purpose-grown lipids have existing uses.

c. Excess lipid biomass taken from other states or nations. This share of limited lipid biomass could not be used elsewhere to replace petroleum with HEFA biofuels. Per capita share of total U.S. production for all uses, rather than of lipids available for biofuel, represents a conservative assumption in this estimate.

d. Distillate fuels mix in 2050 (1 gallon jet fuel to 3 gallons diesel) as described in A7f above.

e. Carbon intensity (CI) values from tables 3, 7-1, and 8 of the California LCFS Regulation.¹⁵ HEFA values shown were derived by apportioning "fats/oils/grease residues" and "any feedstocks derived from plant oils" at 31% and 69%, respectively, based on the data in Table 1 that are cited in note c above.

f. Emissions shift accounting for future emissions that would not occur if other states and nations had access to the lipid feedstock committed to California biofuel refining and combustion in excess of the state per capita share shown (*see* also notes b and c). Shifted emissions were calculated from the difference between HEFA and petroleum CI values for each fuel, applied to its fuels mix percentage of excess lipids shifted to CA for HEFA biofuel. Accounting for this emission shift caused by replacing petroleum with HEFA biofuel here instead of elsewhere, separately from any added land use impact, is consistent with the LCFS¹⁶ and state climate policy regarding "leakage."¹⁷ Total emissions thus include emissions from CA HEFA use of per capita share (calculated from HEFA CI values), excess CA HEFA use shifted to CA (from HEFA CI values), and emissions shift, calculated as described above.

Data references for Table A7.

¹ Davis and Boundy, 2021. Transportation Energy Data Book: Edition 39. U.S. DOE, Oak Ridge National Laboratory: Oak Ridge, TN. https://tedb.ornl.gov/data. See Table 3.15 Survival Rates for Cars and Light Duty Trucks by Vehicle Age; Table 3.13 U.S. Average Vehicle Age, 1970–2019; and tables 3.11 and 3.12 for cars/trucks in operation by age, 1970, 2000, and 2013.

² *Fuel Watch;* California Energy Commission: Sacramento, CA. https://ww2.energy.ca.gov/almanac/petroleum_data/fuels_watch/index_cms.html

³ *Refinery Capacity Data by Individual Refinery as of January 1, 2020;* U.S. Energy Information Administration: Washington, D.C. https://www.eia.gov/petroleum/refinerycapacity.

⁴ LCFS Dashboard; California Air Resources Board: Sacramento, CA.

https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm. <u>See</u> downloads at Figure 2. Alternative Fuel Volumes and Credits; and Figure 10. Share of Liquid Biofuels Produced in-State by Volume.

⁵ Brelsford, R. Global Clean Energy lets contract for Bakersfield refinery conversion project. *Oil & Gas Journal.* **2020.** 9 Jan 2020.

⁶ Initial Study for: Tesoro Refining & Marketing Company LLC—Marathon Martinez Refinery Renewable *Fuels Project;* received by Contra Costa County Dept. of Conservation and Development 1 Oct 2020.

⁷ Application for Authority to Construct Permit and Title V Operating Permit Revision for Rodeo Renewed Project: Phillips 66 Company San Francisco Refinery (District Plant No. 21359 and Title V Facility # A0016); Prepared for Phillips 66, Rodeo, CA by Ramboll US Consulting, San Francisco, CA. May 2021.

⁸ Paramount Petroleum, AltAir Renewable Fuels Project Initial Study; submitted to City of Paramount Planning Division, 16400 Colorado Ave., Paramount, CA. Prepared by MRS Environmental, 1306 Santa Barbara St., Santa Barbara, CA.

⁹ Decommissioning California Refineries: Climate and Health Paths in an Oil State; Jul 2020. A report for Communities for a Better Environment by Greg Karras, Community Energy reSource. Available for download at <u>https://www.energy-re-source.com/decomm</u>

¹⁰ Austin et al., 2021. *Driving California's Transportation Emissions to Zero;* Report No.: UC-ITS-2020-65. Institute of Transportation Studies, University of California. DOI: 10.7922/G2MC8X9X. <u>https://escholarship.org/uc/item/3np3p2t0</u>

¹¹ Ueckerdt et al., 2021. Potential and risks of hydrogen-based e-fuels in climate change mitigation. *Nature Climate Change* <u>https://doi.org/10.1038/s41558-021-01032-7</u> Includes Supplementary Information.

¹² Sustainable Aviation Fuel: Review of Technical Pathways; USDOE Office of Energy Efficiency & Renewable Energy, Bioenergy Technologies Office. DOE/EE-2041. Sep 2020. <u>See esp. page 19 citing</u> ASTM D7566 Annex 2. <u>https://www.energy.gov/eere/bioenergy/downloads/sustainable-aviation-fuel-review-technical-pathways-report</u>

¹³ U.S. Department of Agriculture *Oil Crops Data: Yearbook Tables;* <u>https://www.ers.usda.gov/data-products/oil-crops-yearbook/oil-crops-yearbook/#All%20Tables.xlsx?v=7477.4</u>.

¹⁴ Perlack and Stokes, 2011. U.S. Billion-Ton Update: Biomass Supply for Bioenergy and Bioproducts Industry. U.S. Department of Energy, Oak Ridge National Laboratory: Oak Ridge, TN. ORNL/TM-2011/224.

¹⁵ Low Carbon Fuel Standard (LCFS) Regulation; California Air Resources Board: Sacramento, CA. <u>https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard</u>

¹⁶ LCFS carbon intensity values were used in this estimate, as described in emission estimate note e.

¹⁷ California Health and Safety Code §§ 38505 (j) and 38562 (b) (8).