June 3, 2024

Submitted via https://www.regulations.gov

Nicole Law
Donnique Sherman
Sina Schwenk-Mueller
EPA Region IX
75 Hawthorne St.
San Francisco, CA 94105

Re: Proposal to Approve California SIP Revisions (EPA–R09–OAR–2024–0175; FRL–11888–01–R9)

Dear Ms. Law, Ms. Sherman, and Ms. Schwenk-Mueller:

We are writing to submit these comments on behalf of Voices in Solidarity Against Oil in Neighborhoods, Central California Environmental Justice Network, FracTracker Alliance, the Center for Biological Diversity, and Earthjustice, on the following agency actions—

- EPA's proposal to approve revisions to California's state implementation plan (SIP), including a statewide rule and six air district rules regulating emissions of volatile organic compounds (VOCs) from crude oil and natural gas facilities, and reasonably available control technology (RACT) demonstrations for the 2008 and 2015 ozone national ambient air quality standards (NAAQS) for sources covered by EPA's 2016 Control Techniques Guidelines for the Oil and Gas Industry (Oil and Gas CTG)[1] for the Sacramento Metropolitan Air Quality Management District (AQMD), San Joaquin Valley Unified Air Pollution Control District (APCD), Ventura County APCD, and Yolo-Solano AQMD;[2] and
- EPA's proposal to conditionally approve SIP revisions based on the RACT demonstrations for the 2008 and 2015 ozone NAAQS for sources covered by the Oil and Gas CTG for the South Coast AQMD.[3]

These comments build on comments submitted on June 13, 2022, in connection with the prior iteration of this rulemaking, which we incorporate herein by reference.[4]

California's proposed SIP does not meet the minimum requirements of RACT and will not qualify for EPA approval under the Clean Air Act unless and until serious deficiencies are corrected. We urge the EPA to disapprove the SIP revisions and instruct California to resubmit a SIP that includes, at minimum, (1) a full disclosure and analysis of the environmental justice impacts of the SIP; (2) RACT requirements applicable to all oil and gas wells in nonattainment

[1] EPA, *Control Techniques Guidelines for the Oil and Natural Gas Industry*, EPA-453/B-16-001 (Oct. 2016) (hereafter Oil and Gas CTG), https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf.
[2] 89 Fed. Reg. 36729, 26729-37, Docket No. EPA–R09–OAR–2024–0175; FRL–11888–01–R9 (May 3, 2024).
[3] *Id.*
[4] Letter from Hollin Kretzmann, Center for Biological Diversity, et al., to Nicole Law, EPA Region IX, et al., Comment ID EPA-R09-OAR-2022-0416-0072 (June 13, 2022).

areas, regardless of production volume (this includes idle wells), the gravity of oil, and whether the wellhead is connected to other equipment; and (3) improved monitoring and reporting requirements.

Likewise, EPA's guidelines (particularly the Oil and Gas CTG) and regulations are inconsistent with the Clean Air Act to the extent they recommend exemptions for low production wells (including idle wells), heavy oil, and wellhead-only sites, and must be revised to ensure that RACT such as optical gas imaging (OGI) or Method 21 inspections are in use at all wells in all oil-producing states with moderate or higher ozone non-attainment areas.

Together, California's SIP, the Oil and Gas CTG, and EPA's wellhead-only regulation create "create[] a potent loophole for polluters to walk through."[5] Fugitive emissions from all well sites—whether idle or active, heavy or light, containing infrastructure or wellhead only—are a category of VOC sources covered by the Oil and Gas CTG, represent a major source of VOC emissions in California and a major public health threat, and merit full RACT protections.

I. EPA must conduct a full analysis of environmental justice impacts of this SIP.

Figure 1:

Figure 2: CalEnviroScreen 4.0 Results Map

[5] *Sierra Club v. U.S. EPA*, 972 F.3d 290, 297 (3d Cir. 2020).

California has some of the worst air quality in the nation. These poor air quality conditions are borne most heavily by the state's environmental justice communities, as depicted on the maps[6] above. A significant portion of this air pollution can be attributed to oil and gas activity. VOC emissions from oil and gas activity result in the formation and increased presence of smog, contributing to adverse health impacts for communities near oilfields. Even so, neither the State nor EPA considered environmental justice factors in evaluating the proposed SIP or RACT standards, despite Executive Order 12898 directing environmental justice analysis in federal decisionmaking.[7] The Order's mandate to incorporate and promote environmental justice "to the greatest extent practicable" is clear, but this SIP fails to meet this requirement by exempting significant amounts of VOC near low-income communities and communities of color from the RACT requirements.

Ozone, the main component of smog, is a corrosive air pollutant that inflames the lungs, constricts breathing, and likely kills people.[8] Ozone causes and exacerbates asthma attacks, emergency room visits, hospitalizations, and other serious health harms.[9] Ozone-induced health problems can force people to change their ordinary activities, requiring children to stay indoors and forcing people to take medication and miss work or school.[10]

Ozone can harm healthy adults, but others are more vulnerable.[11] Because their respiratory tracts are not fully developed, children are especially vulnerable to ozone pollution, particularly when they have elevated respiratory rates, as when playing outdoors.[12] People with lung disease and the elderly also have heightened vulnerability.[13] People with asthma suffer more severe impacts from ozone exposure than healthy individuals do and are more vulnerable at lower levels of exposure.[14]

Ozone also damages vegetation and forested ecosystems, causing or contributing to widespread stunting of plant growth, tree deaths, reduced carbon storage, and reduced crop yields.[15] The damage includes tree-growth losses reaching 30-50% in some areas, and widespread visible leaf injury, including 25-37% of sites studied in just one state.[16] By harming vegetation, ozone can also damage entire ecosystems, leading to ecological and economic losses.[17]

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[6] Figure 1: CARB Air Quality Planning and Science Division, 2022 Area Designations for State Ambient Air Quality Standards, Ozone (Nov. 2022); Figure 2: Cal. Office of Environmental Health Hazard Assessment, *CalEnviroScreen 4.0 Results Map*, https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40 (last accessed June 3, 2024).
[7] Executive Order 12898 (Clinton), 59 Fed. Reg. 7629 (Feb. 16, 1994).
[8] EPA, National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,292, 65,308-09 (Oct. 26, 2015); EPA, Integrated Science Assessment for Ozone and Related Photochemical Oxidants, at 2-20 to -24, Table 2-1 (Feb. 2013) (EPA-HQ-OAR-2008-0699-0405) ("Science Assessment").
[9] *See, e.g.,* EPA, Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards, at 3-18, 3-26 to -29, 3-32 (Aug. 2014) (EPA-HQ-OAR-2008-0699-0404) (Policy Assessment); Science Assessment at 2-16 to -18, 2-20 to -24 Table 2-1.
[10] *See, e.g.,* Policy Assessment at 4-12.
[11] *See* 80 Fed. Reg. at 65,310.
[12] *See, e.g.,* Policy Assessment at 3-81 to -82.
[13] *See* 80 Fed. Reg. at 65,310.
[14] *Id.* at 65,311 n.37, 65,322.
[15] Policy Assessment at 5-2 to -3; Science Assessment at 9-1.
[16] Policy Assessment at 5-13; Science Assessment at 9-40.
[17] 80 Fed. Reg. at 65,370, 65,377.

Areas within a state classified as being in “moderate” nonattainment or higher for the 2008 and 2015 8-hour ozone NAAQS must implement RACT. California has five such nonattainment areas[18] which reflect a correlation between ozone pollution, heavy oil and gas activity, adverse health effects, and environmental justice communities.

For example, the San Joaquin Valley Air Basin is classified as being in “Extreme” nonattainment for the 2008 and 2015 8-hour ozone NAAQS,[19] and is home to a number of communities with some of the highest overall CalEnviroScreen scores indicative of disadvantaged communities “burdened by multiple sources of pollution and with population characteristics that make them more sensitive to pollution.”[20] In particular, a sampling of census tracts from the Bakersfield area, below, illustrates the strong overlap between environmental injustice, air quality, and oil and gas drilling in California, including downtown Bakersfield tracts with both overall scores and asthma scores as high as the 99th percentile:[21]

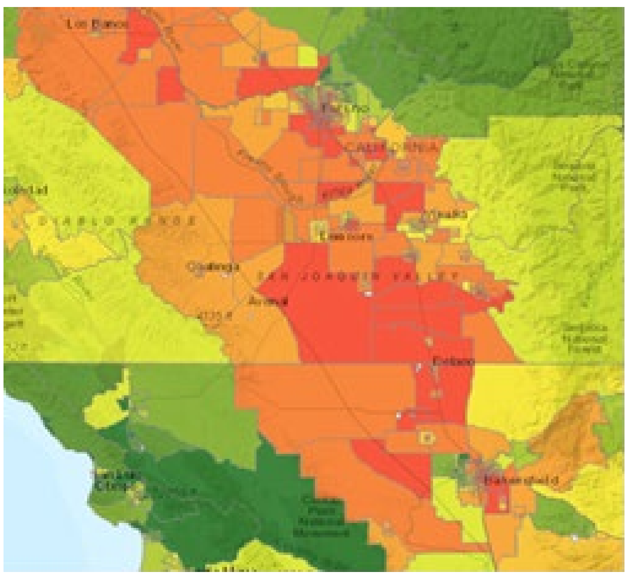

Figure 3: CalEnviroScreen Map, San Joaquin Valley

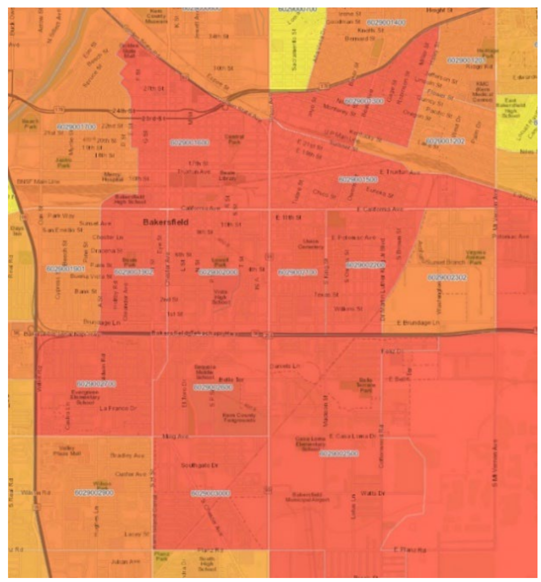

Figure 4: CalEnviroScreen Map, Downtown Bakersfield

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[18] For the 2008 and 2015 8-hour ozone NAAQS, South Coast Air Basin, Riverside County / Coachella Valley, San Joaquin Valley Air Basin, Sacramento Metropolitan, and Ventura County were rated either “serious,” “severe,” or “extreme.” EPA, *TSD for EPA’s Rulemaking for the California State Implementation Plan* at 1-2 (April 2022).
[19] *See* 40 C.F.R. § 81.305.
[20] *See, e.g.,* Cal. EPA, *Final Designation of Disadvantaged Communities Pursuant to Senate Bill 535* at 15, Figure 2 (May 2022) (map of disadvantaged communities in the Los Angeles Region), https://calepa.ca.gov/wp-content/uploads/sites/6/2022/05/Updated-Disadvantaged-Communities-Designation-DAC-May-2022-Eng.a.hp_-1.pdf. *See also id.* at 19, Figure 6 (map of disadvantaged communities in the San Joaquin Valley); California Department of Public Health Environmental Health Investigations Branch, *California Asthma Dashboard* (discussing asthma rates by county), https://www.cdph.ca.gov/Programs/CCDPHP/DEODC/EHIB/CPE/Pages/CaliforniaBreathingCountyAsthmaProfile.aspx (accessed May 31, 2024).
[21] *See, e.g.,* CalEnviroScreen 4.0 at Census Tract 6029002000 (99 overall, 95 asthma), 6029001902 (92 overall, 97 asthma), 6029001600 (95 overall, 99 asthma), 6029001500 (95 overall, 94 asthma), 6029001300 (93 overall, 97 asthma), 6029002700 (91 overall, 97 asthma), 6029002600 (95 overall, 91 asthma). Available at https://experience.arcgis.com/experience/11d2f52282a54ceebcac7428e6184203/page/CalEnviroScreen-4_0/ (accessed June 3, 2024).

Similarly, the South Coast Air Basin is classified as being in "Extreme" nonattainment for the 2008 and 2015 8-hour ozone NAAQS.[22] A sampling of census tracts from the heavily drilled Wilmington area of Los Angeles area, depicted on the maps below, once again confirms the linkage between oil and gas production, air pollution, and environmental injustice, including overall scores as high as the 99th percentile and asthma scores in the 80s.[23]

Figure 5: CalEnviroScreen Map, Los Angeles

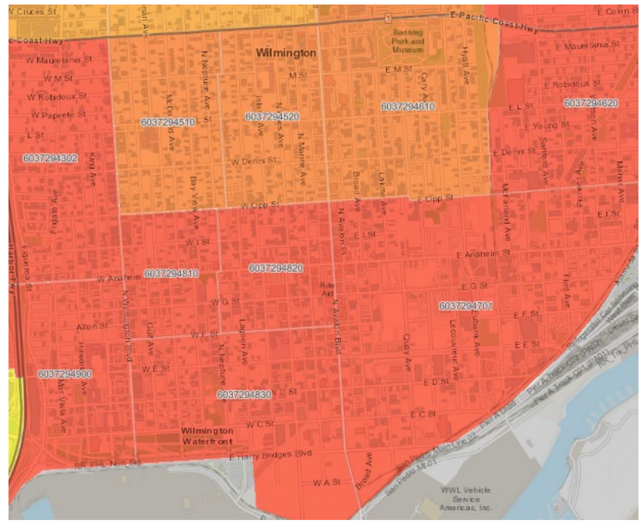

Figure 6: CalEnviroScreen Map, Wilmington Area of Los Angeles

Frontline communities live with oil and gas wells in their neighborhoods. California has no statewide setback to separate oil wells from homes, schools, or other sensitive receptors.[24] As a result, Californians are acutely aware of the links between oil and gas wells and their health. The recent discovery of fugitive emissions from dozens of leaking idle wells in Kern County provided a stark example of the dangers of living close to idle wells. These wells were found leaking high concentrations of methane, some at levels high enough to be explosive.[25]

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[22] EPA, *TSD for EPA's Rulemaking for the California State Implementation Plan* at 1.

[23] *See, e.g.,* CalEnviroScreen 4.0 at Census Tract 6037294302 (91 overall, 82 asthma), 6037294900 (96 overall, 81 asthma), 6037294810 (91 overall, 83 asthma), 6037294820 (95 overall, 83 asthma), 6037294830 (98 overall, 83 asthma), 6037294701 (99 overall, 83 asthma), 6037294620 (91 overall, 83 asthma), 6037294120 (97 overall, 83 asthma).

[24] The California legislature enacted a statewide setback of 3,200 feet between oil and gas wells and sensitive receptors like homes and schools in recognition of the "direct health impacts from proximity to oil extraction," which "disproportionately impact[] Black, indigenous, and people of color in California," S.B. 1137, § 1, 2022 Leg., Reg. Sess. (Cal. 2022), but the legislation is currently on hold pending the outcome of an industry-funded referendum on the November 2024 ballot, Jim Newton, *In 2024, who will California voters believe more: Oil companies or Jane Fonda?*, Cal Matters, Dec. 21, 2023, https://calmatters.org/commentary/2023/12/voter-referendum-jane-fonda-oil/.

[25] Janet Wilson, *21 Oil Wells Now Found Leaking Methane Near California Homes*, Desert Sun, June 2, 2022, https://www.desertsun.com/story/news/environment/2022/06/02/number-oil-wells-leaking-methane-near-californiahomes-climbs-21/7484046001/. *See also Inspectors Find 14th Oil Well Leaking Methane in Bakersfield Residential Area*, Bakersfield Californian, May 31, 2022, https://www.bakersfield.com/news/inspectors-find-14th-oil-well-leaking-methane-in-bakersfield-residentialarea/article_76b33f18-e127-11ec-98ae-cbb404e66185.html.

EPA admits that it did not conduct an environmental justice analysis for this rulemaking.[26] Eschewing such an analysis is inconsistent with Executive Order 12898, which directs agencies, to the extent practical and appropriate, to "use [environmental justice-related] information to determine whether their programs, policies, and activities have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations."[27]

While EPA maintains that "the CAA and applicable implementing regulations neither prohibit nor require" an environmental justice review in the present context,[28] EPA also admits that RACT must be based on case-specific evaluations of circumstances in particular jurisdictions and information submitted by members of the public.[29] Likewise, EPA insists that costs are a relevant concern in determining what does or does not qualify as RACT.[30]

As Californians living and working on the frontlines of oil production suffer astronomical public health costs (discussed further *infra*), environmental justice is directly relevant here as a case- and jurisdiction-specific factor illustrating why RACT is necessary. RACT-related reductions in VOC emissions would results in major improvements to the health and wellbeing of Californians living closest to oil wells, including cost savings due to fewer missed days of work, fewer visits to emergency rooms for asthma attacks, and reductions in premature mortality. It is essential that EPA acts with this big picture in mind when making decisions about RACT, rather than dismissing technologically superior options due to concerns about costs to industry.

Given oil and gas activity's disproportionate harm to environmental justice communities, the exemptions allowing wells located in these communities to evade pollution control requirements under the Clean Air Act will have disproportionate impacts on the same communities that have historically suffered from oil and gas production. As such, EPA must, at minimum, provide a thorough analysis of the disproportionate impacts on California's frontline communities under the proposed SIP.

II. EPA must revise its guidelines to include RACT protections to reduce VOC emissions from all low production wells, including idle wells.

The Clean Air Act requires implementation of reasonably available control technology (RACT) in state implementation plans for states like California with ozone nonattainment areas classified as Moderate or above.[31] EPA has made clear that "all sources contributing to the nonattainment situation are required to implement restrictive available control measures even if it requires

[26] 89 Fed. Reg. at 36737.
[27] Executive Order 12898 (Clinton) 59 Fed. Reg. 7629 (Feb. 16, 1994) 3-302(a).
[28] 89 Fed. Reg. at 36737.
[29] EPA Memorandum from Anna Marie Wood, Director of Air Quality Policy Division, to Regional Air Division Directors, Implementing Reasonably Available Control Technology Requirements for Sources Covered by the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry at 2 (Oct. 20, 2016) (hereafter Wood Memo), https://www.epa.gov/sites/default/files/2016-10/documents/implementing_reasonably_available_control_technology_requirements_for_sources_covered_by_the_2016_control_techniques_guidelines_for_the_oil_and_natural_gas_industry.pdf.
[30] *See* Oil and Gas CTG at 1-1 (defining RACT as including economic feasibility).
[31] CAA § 182(b)(2), 42 U.S.C. § 7511a(b)(2).

significant sacrifice."[32] EPA has long maintained that "RACT should represent the toughest controls considering technological and economic feasibility that can be applied to a specific situation" and that "[a]nything less than this is by definition less than RACT."[33] While California's SIP applies RACT requirements at light-oil, low production wells, it exempts significant volumes of oil and gas emissions by failing to apply RACT requirements at heavy-oil, low production wells.

Additionally, EPA erroneously considers low production wells, including idle wells, outside the scope of the instant rulemaking,[34] meaning that a huge additional volume of emissions could evade RACT requirements in other oil-producing states with nonattainment areas. In reality, low-producing and idle wells represent a category of sources that *are* covered by the 2016 Oil and Gas CTG, and the VOC emissions from this category are substantial. "Rules affecting major sources in nonattainment areas generally cannot exempt activities subject to relevant CTGs or other presumptive RACT…"[35] Accordingly, EPA improperly failed to consider emissions from low production wells when determining that RACT is unnecessary at active heavy-oil wells, and failed altogether to consider the need for RACT at light-oil low production wells, and EPA's resulting proposal to uphold California's air regulations is fatally flawed. Furthermore, EPA's proposal to approve California's ozone SIP is not "based on a consideration of the relevant factors" as required by the Administrative Procedure Act.[36]

A. Fugitive emissions from idle and marginally producing wells fall within the category of sources covered by the 2016 Oil and Gas CTG.

EPA's guidelines would exempt the vast majority of California's oil and gas wells from RACT requirements under its carveout for wells that produce less than 15 barrels of oil equivalent per day. While California's rules provide coverage for light-oil, low-production and idle wells, it is important for EPA to revise the Oil and Gas CTG to ensure that RACT applies to all low production and idle wells in all oil-producing states with moderate or worse ozone nonattainment.

The Clean Air Act requires RACT protections for all low production wells, including California's 40,000 idle wells.[37] RACT applies to "[e]ach category of VOC sources in the area covered by a [control techniques guideline (CTG)] document."[38] Fugitive emissions from idle wells are a "category" of VOC sources "covered by" EPA's 2016 CTG "for the Oil and Natural Gas Industry" (Oil and Gas CTG).[39] Accordingly, EPA's position that RACT is only necessary for oil

[32] Memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management at U.S Env't Prot. Agency, to Regional Administrators, Regions I - X, at 5 (Dec. 9, 1976) (hereafter Strelow Memo), https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19761209_strelow_ract.pdf.
[33] *Id.* at 3.
[34] 87 Fed. Reg. at 59317.
[35] EPA, Little Bluebook at 3.
[36] *State of Mich. v. Thomas*, 805 F.2d 176, 181–82 (6th Cir. 1986).
[37] EPA defines "low production wells" as wells "where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production," which necessarily includes idle wells that produce 0 boe per day. 81 Fed. Reg. 35824, 35856 (June 3, 2016).
[38] CAA § 182(b)(2)(A), 42 U.S.C. § 7511a(b)(2)(A).
[39] *See generally* Oil and Gas CTG, *supra*.

wells that produce more than 15 boe per day is inconsistent with the Clean Air Act. Any SIP or federal implementation plan approvals on this basis would be arbitrary, capricious, and an abuse of discretion.

EPA's Oil and Gas CTG "covers select sources of VOC emissions in the onshore production and processing segments of the oil and natural gas industry," specifically including "fugitive emissions."[40] In particular, the Oil and Gas CTG applies to "existing sources of VOC emissions," including emissions covered by new source performance standards (NSPS) "establish[ing][41] VOC emission standards for certain new and modified sources in the oil and gas industry."[42] As one example, the Oil and Gas CTG cites a 2016 rule finalizing VOC standards "for several emission sources not previously covered by the NSPS," including "fugitive emissions from well sites and compressor stations." This fugitive emissions rule explicitly covers fugitive emissions from low-producing and idle wells.[43]

In the final rule setting NSPS for fugitive emissions from well sites, EPA discussed its initial proposal to exclude low production oil and gas wells from fugitive emissions monitoring and repair requirements, and its decision to reverse course based on the following:

> Based on the data from DrillingInfo, 30 percent of natural gas wells are low production wells, and 43 percent of all oil wells are low production wells…[T]his type of well…is typically unmanned and not visited as often as other well sites that would allow fugitive emissions to go undetected…[T]he potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same.[44]

As a result, and based "in particular, [on] the large number of low production wells and the similarities between well sites with production greater than 15 boe per day and low production well sites in terms of the components that could leak and the associated emissions," EPA stated that "we are not exempting low production well sites from the fugitive emissions monitoring program. Therefore, the collection of fugitive emissions components at *all* new, modified or reconstructed well sites is an affected facility and must meet the requirements of the fugitive emissions monitoring program."[45]

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[40] Oil and Gas CTG at 3-5.
[41] *Id.* at 2-4.
[42] *Id.* at 2-1 (citing 81 Fed. Reg. 35824 (June 3, 2016)).
[43] *See* 81 Fed. Reg. 35824, 35827 (June 3, 2016) ("The final fugitive standards apply to low production wells.").
[44] *Id.* at 35856. Notably, while EPA temporarily reversed its position on low-production wells in a 2020 technical rule on cost-effectiveness grounds and based on an assumption that low production wells emit lower amounts of pollution, a 2021 proposed rule that recently became final admitted that both of these rationale were without basis and reinstated the 2016 NSPS policy on low production wells. 86 Fed. Reg. 63110, 63158-59 (Nov. 15, 2021); 89 Fed. Reg. 16820, 16989-90 (Mar. 8, 2024).
[45] 81 Fed. Reg. at 35827 (emphasis added). *See also* 40 C.F.R. § 60.5397a (requiring VOC emissions reductions such as monitoring, repair, and recordkeeping requirements at "affected facilities"); 40 C.F.R. § 60.5365a(i) (generally defining "an affected facility" to include "the collection of fugitive emissions components at a well site"); 40 C.F.R. § 60.5430a (defining the "[c]rude oil and natural gas source category" as "[c]rude oil production, which includes the well" and "[n]atural gas production, processing, transmission, and storage, which include the well…")

Since fugitive emissions from low production oil and gas rules represent an existing source of VOC emissions from the oil and gas industry with established NSPS in place, such emissions represent a "category" that is "covered by" the Oil and Gas CTG for purposes of section 182(b) of the Clean Air Act, meaning that California and other moderate+ ozone non-attainment states must impose RACT requirements to address this source of emissions.[46] Moreover, EPA fails to provide a justification for exempting low-production and idle wells given its own assessment that "the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same."[47]

Based on the above, while the Oil and Gas CTG attempts to carve out low production wells from the scope of coverage,[48] the effect is simply to make a *recommendation* that RACT is unnecessary for this covered category of emissions, the same way the CTG makes a *recommendation* that RACT is unnecessary for active wells that produce heavy oil, as discussed further *infra*. Moreover, the CTG itself "encourage[s] air agencies to consider site-specific data from [wells producing under 15 barrels per day] in their RACT analyses."[49] The proposed SIP does not make any such consideration nor does it require local air districts to do so.

EPA has never disputed that fugitive emissions from *active* wells fall within the scope of the Oil and Gas CTG—equally so do fugitive emissions from low production wells. California must continue imposing RACT for both emissions categories,[50] and EPA must revise the Oil and Gas CTG to make clear that coverage for low production wells is part of the federal minimum standards expected for compliance with the Clean Air Act's RACT requirements. Likewise, EPA must provide a substantive response to our comments about low production and idle wells consistent

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[46] While there is an exception in the regulations for sites that "only contain[] one or more wellheads," 40 C.F.R. § 60.5365a(i)(2), it is important to note that wells producing *any* volume of oil or gas, even amounts less than 15 boe, would necessarily have production-related components onsite, and many idle wells (defined in California as being out of production for 24 consecutive months, Cal. Pub. Res. Code, § 3008(d)) should still have production-related components onsite because the entire premise of leaving a well idle rather than plugging and abandoning it is the potential to return it to active production. *See* Cal. Pub. Res. Code, § 3206.1(a)(4) (allowing an operator to demonstrate that a well is "idle" and not "deserted" by providing "an engineering analysis demonstrating...that it is viable to return the idle well to operation in the future").

[47] 81 Fed. Reg. at 35856; *see also* 86 Fed. Reg. at 63159 ("[D]ue to the wide variation in well characteristics, types of oil and gas products and production levels, gas composition, and types of equipment at well sites, there is considerable uncertainty regarding the relationship between the fugitive emissions and production levels. Accordingly, the EPA no longer believes that production levels provide an appropriate threshold for any exemption from fugitive monitoring.").

[48] *See* Oil and Gas CTG at 9-1 ("For purposes of this CTG, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at well sites with an average production of greater than 15 barrel equivalents per well per day," and "[f]or the purposes of this CTG, fugitive emission reduction recommendations would not apply to well sites that only contain wellheads").

[49] CTG at 9-38.

[50] As a factual matter, CARB's Leak Detection and Repair standards *do* generally apply to fugitive emissions from light-oil idle wells. *See* Cal. Code Regs., tit. 17, §§ 95666, 95669(a), (c)(2) (making CARB's leak detection requirements applicable to "owners and operators of equipment and components associated with . . . crude oil or natural gas production" "regardless of emissions level or well status," except for components "used exclusively for" heavy oil). Nevertheless, it is important for EPA to clarify as a matter of federal law that RACT is mandatory for fugitive emissions of VOCs from *all* oil wells.

with EPA's obligations under the Clean Air Act and Administrative Procedure Act,[51] rather than dismissing such comments offhand.[52]

B. RACT for idle and marginally producing wells is necessary due to the scope of the emissions problem from idle and marginally producing wells.

1. Low producing and idle wells represents a huge source of statewide VOC emissions.

According to CalGEM's online database, California currently has around 40,000 idle wells, which comprise 39 percent of all the unplugged wells in the state.[53] By one estimate, two-thirds of those idle wells are leaking methane.[54] In 2020, researchers identified a combined total of 69,425 idle wells and economically marginal wells, 2,975 wells at high risk of becoming orphans in the near future, and 2,565 wells that were likely orphans, meaning there is no owner or operator for those wells.[55] The researchers defined "marginal" wells as those producing less than 5 barrels per day.[56] California currently has 65,019 unplugged oil and gas wells, with 59,772 (91.9%) of those qualifying as idle or producing less than an average of 15 barrels per day.[57]

Unplugged wells can be "super-emitting" sources of methane,[58] which EPA recognizes as a proxy for VOC emissions.[59] An estimated 30 million tons of methane spewed from one such idle

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[51] *See Allied Local & Reg'l Mfrs. Caucus v. EPA*, 215 F.3d 61, 80 (D.C. Cir. 2000) ("For an agency's decisionmaking to be rational, it must respond to significant points raised during the public comment period.").

[52] In responding to our June 13, 2022 comments discussing the problem of methane and VOC leaks from idle wells in California in relation to the heavy-oil exemption, EPA acknowledged that "leaking wells might implicate the RACT requirement" for *non*-idle wells but failed to address the merits of our complaint regarding the lack of RACT for idle wells, on the incorrect basis that "commenters' concerns regarding idle wells relate to emissions from sources not covered by the CTG . . . and are therefore beyond the scope of this rulemaking." *Compare* Letter from Hollin Kretzmann, *supra*, *with* 87 Fed. Reg. at 59317.

[53] CalGEM Data Dashboard, https://www.conservation.ca.gov/calgem/Online_Data/Pages/WellSTAR-Data-Dashboard.aspx (accessed May 28, 2024); Letter from Kyle Ferrar, Western Program Director, FracTracker Alliance Re: Expert Witness Comments on Scope of U.S. EPA State Implementation Plan of RACT Requirements for Oil and Gas Sites at 2 (June 3, 2024).

[54] Lebel, E. et al., Methane Emissions from Abandoned Oil and Gas Wells in California, Environmental Science and Technology, 54, 14617-14262 (2020).

[55] J. Boomhower et al., *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells*, California Council on Science and Technology at 16 (2020), https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf.

[56] *Id.* at 16.

[57] Letter from Kyle Ferrar at 3.

[58] M. Kang et al., *Identification and characterization of high methane-emitting abandoned oil and gas wells*, Proceedings of the National Academy of Sciences (2016), https://www.pnas.org/content/pnas/113/48/13636.full.pdf; J. Sullivan, *Abandoned wells can be 'super- emitters' of greenhouse gas*, Princeton University Office of Engineering, Dec. 9, 2014, https://www.princeton.edu/news/2014/12/09/abandoned-wells-can-be-super-emittersgreenhouse-gas.

[59] *See* 87 Fed. Reg. at 59317 ("With respect to the commenters' concerns regarding leaking wells, the EPA agrees that if wells are leaking methane, they are likely to also leak VOCs.")

well in California.[60] This would equate to **8.34 tons** of VOCs from a single well.[61] Countless other idle and deserted wells may also be leaking significant quantities of methane.

Inspections conducted by CalGEM and community watchdogs over the past two years further demonstrate wells in frontline communities pose a nuisance to nearby residents. These inspections exposed the "widespread" leaking of methane and other air pollutants from dozens of oil and gas wells and infrastructure in the Bakersfield, Arvin-Lamont, Los Angeles, and Ventura areas, including many leaks from idle wells and some wells leaking methane at explosive levels.[62]

Given these high leakage rates and known instances of super-emitter wells, EPA's Oil and Gas CTG does not adequately explain why low-producing and idle wells should be exempt from RACT requirements.

2. VOCs from low producing and idle wells are particularly dangerous to frontline communities.

Most wells located within 3,200 feet of communities in California "produce very low volumes of oil and already have high counts of idle wells," including "28% idle in Wilmington, 25% in Inglewood, and 56% in Long Beach."[63] It would be wrong for EPA to allow operators to use idling to avoid incremental expense associated with RACT inspections of these wells, when doing so shifts those costs to the health of frontline communities and, ultimately, the pockets of all Californians.

An extensive and still growing body of toxicological and epidemiological studies confirms the link between proximity to oil production and adverse health outcomes. Based on its review of these studies, the California Oil and Gas Public Health Rulemaking Scientific Advisory Panel convened by CalGEM concluded with a "high level of certainty" that (1) "health-damaging air pollutants, including criteria air pollutants and toxic air contaminants, are more concentrated near [oil and gas drilling] activities compared to further away," and (2) serious harm to the public is occurring within 1 kilometer (3,200 feet) of oil activities, particularly adverse birth and

[60] M. Frazier, *Gas Companies Are Abandoning Their Wells, Leaving Them to Leak Methane Forever*, Bloomberg, Sept. 17, 2020, https://www.bloomberg.com/news/features/2020-09-17/abandoned-gas-wells-are-left-to-spew-methane-for-eternity.
[61] EPA uses a VOC:Methane ratio of 0.278 in the 2016 Oil and Gas CTG. CTG at 5-7.
[62] *See, e.g.,* John Cox, *State Finds 27 Oil Wells Leaking Methane in Arvin-Lamont Area*, Bakersfield Californian, June 1, 2023, https://www.bakersfield.com/news/state-finds-27-oil-wells-leaking-methane-in-arvin-lamont-area/article_52120332-00da-11ee-b466-83e7f8b280c5.html; Kyle Ferrar, *FracTracker Finds Widespread Hydrocarbon Emissions from Active and Idle Oil and Gas Wells and Infrastructure in California*, FracTracker Alliance, Aug. 22, 2022, https://www.fractracker.org/2022/08/fractracker-finds-widespread-hydrocarbon-emissions-from-active-idle-oil-and-gas-wells-and-infrastructure-in-california/; CalGEM, *Well Inspections and Repair Updates* (last updated May 17, 2023), https://www.conservation.ca.gov/well-inspections-repair-updates#:%7E:text=July%2019%2C%202022,all%20leaks%20are%20properly%20fixed.&text=All%20six%20wells%20previously%20found%20to%20be%20leaking%20methane%20are%20repaired.,-Post%2Drepair%20inspections.
[63] Kyle Ferrar, *People and Production: Reducing Risk in California Extraction*, FracTracker Alliance, Dec. 17, 2020, https://www.fractracker.org/2020/12/people-and-production/.

respiratory outcomes.[64] The Panel also found that such harm will remain ongoing until a full phaseout of neighborhood drilling.[65]

Indeed, CalGEM issued a Finding of Emergency in December 2022 acknowledging the direct and significant health impacts associated with proximity to oil production at distances less than 3,200 feet.[66] The agency's emergency finding closely tracks the California Legislature's earlier findings that there are "direct health impacts from proximity to oil extraction," with such negative impacts "disproportionately" experienced by "Black, indigenous, and people of color . . . who are most likely to live in close proximity to oil extraction activities and who are the most vulnerable to the negative impacts of climate change."[67] Based on these concerns, CalGEM found that urgent action was "necessary for immediate preservation of the public peace, health, safety, or general welfare."[68]

More recently, empirical modeling performed by researchers at the University of California Santa Barbara and published in a peer-reviewed study has confirmed earlier research that a greater distance of separation from oil and gas wells results in fewer deaths due to reduced air pollution, particularly in "disadvantaged communities."[69]

Thus, the proposed SIP's exemption for low-producing wells is likely to lead to disproportionate health and environmental impacts on communities already overburdened by pollution. EPA should reject the SIP, but at minimum, evaluate the SIP's environmental justice consequences of the low-producing and idle well exemption, as discussed above.

C. Absent RACT, extended VOC leaks are likely at low producing and idle well sites.

EPA repeatedly expressed concern over the potential for active production, light-oil wells to leak VOCs over extended periods of time in connection with its initial partial disapproval of CARB's rules. That same rationale applies equally to low producing and idle wells, whether they involve light oil or heavy oil.

For example, EPA initially disapproved of subsections 95668(c)(4)(F) and 95668(d)(9) of the CARB Oil and Gas Methane Rule because they "potentially allowed a leak to go unrepaired for an additional year after being identified," whereas "the 2016 Oil and Gas CTG does not allow for

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[64] Letter from Cal. Oil and Gas Public Health Rulemaking Scientific Advisory Panel, Response to CalGEM Questions at 1-11 (Oct. 1, 2021), https://www.conservation.ca.gov/calgem/Documents/public-health/Public%20Health%20Panel%20Responses_FINAL%20ADA.pdf.
[65] *Id*. at 12-14.
[66] CalGEM, SB 1137 First Emergency Implementation Reguls.: Notice of Proposed Emergency Rulemaking Action at 2-3 (Dec. 19, 2022), https://www.conservation.ca.gov/calgem/Documents/SB%201137%20%20Emergency%20Regulations%20-%20Rulemaking%20Notice.pdf.
[67] *Id*. at 3 (quoting S.B. 1137, § 1, 2022 Leg., Reg. Sess. (Cal. 2022)).
[68] *Id*. at 2.
[69] Ranjit Deshmukh et al., *Equitable Low-Carbon Transition Pathways for California's Oil Extraction*, 8 Nature Energy 597, 600, 603 (2023), https://doi.org/10.1038/s41560-023-01259-y.

this extended timeline."[70] But failure to apply RACT inspection requirements to components used at low producing and idle well site could have an even worse effect—allowing leaks to continue indefinitely.

Similarly, EPA initially disapproved of Subsections 95668(c)(3)(D)(1)(a), (c)(4)(D)(1)(a), (d)(6)(A)(1) and subsections 95669(h)(4)(A)(1) and (i)(5)(A)(1) of the CARB Oil and Gas Methane Rule, for "provid[ing] an open-ended and potentially indefinite period during which a leak could remain unrepaired."[71] Again, the same rationale applies to exempting low producing and idle wells from inspections.

As a third example, EPA initially disapproved of Subsection 95669(i)(1) of the CARB Oil and Gas Methane Rule, which required leaks of 1,000–9,999 ppm to be repaired within 14 days, compared to the Oil and Gas CTG's recommendation that operators attempt repairs within 5 days of the detected leak.[72] Plenty of wells in California are leaking at higher levels for longer time periods due to the low production exemption, and go undetected but for community science.[73]

D. EPA has offered no rationale for excluding low-producing and idle light-oil wells from RACT.

As discussed above, idle and marginally producing wells are a significant source of VOC emissions,[74] yet EPA has erroneously interpreted low production wells as falling outside the scope of the instant rulemaking. Accordingly, EPA has made no attempt to analyze whether an exemption for idle wells would be justified for any reason, such as inspections with optical gas imaging failing to "expedite attainment."[75] Indeed, such a claim would be unsupportable in light of EPA's own admission that OGI monitoring programs have an effectiveness rate of "40 to 99 percent" emissions reductions.[76] Likewise, EPA has made no claim and offered no evidence that inspections at low production and idle light-oil wells would be economically infeasible, to the extent economic feasibility is a permissible limitation (see below). As a result, EPA's failure to require RACT for low producing and idle wells is wholly unsupported. Finalizing the proposed rule in this respect would be arbitrary, capricious, and an abuse of discretion.[77]

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[70] 89 Fed. Reg. at 36732.
[71] *Id*.
[72] *Id.* at 36733.
[73] Wilson, *supra*.
[74] *See also* Oil and Gas CTG at 9-19 ("[F]ugitive emissions from components are a significant source of VOC emissions from well sites and gathering and boosting stations.").
[75] *See Natural Resources Defense Council v. E.P.A.*, 571 F.3d 1245, 1252 (D.C.Cir. 2009) (stating that "EPA ha[s] discretion to conclude that a measure was not 'reasonably available' if it would not expedite attainment").
[76] Oil and Gas CTG at 9-20.
[77] *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (stating that agency action is arbitrary and capricious if the agency "entirely failed to consider an important aspect of the problem"); *Sierra Club v. United States EPA* (3d Cir. 2020) 972 F.3d 290, 305 ("While we defer to the agency's expertise, the agency's decisions must nevertheless be rational and supported by record evidence").

III. California's SIP is legally deficient because it fails to apply RACT requirements to VOCs emitted from wells producing heavy oil.

California's proposed SIP fails to meet Clean Air Act requirements because it exempts wells producing heavy oil from RACT requirements. Any well producing oil with an API gravity of 20 degrees or less would be exempt from the leak detection requirements under the SIP.[78] Because a large proportion of production in California would qualify as heavy oil, the exemption leaves substantial VOC emissions unaddressed. Moreover, while the exemption appears as a recommendation in the Oil and Gas CTG, this document is mere guidance and EPA admits that it is states' duty to conduct a case-by-case analysis to determine when, as here, the federal guidance does not go far enough toward achieving RACT.[79]

A. VOCs from heavy oil are a huge source of ozone-causing emissions in California.

Heavy oil makes up the vast majority of production in California. In 2018, 68% of California's crude oil production was heavy.[80] According to CalGEM production data, 74% of the state's production over the last three years has been crude with API gravity less than 20 degrees.[81] And of the 65,019 unplugged oil and gas production wells in the state, 51,743 (79.6%) reported production of oil with an average API gravity value of less than 20 degrees, based on a ten-year average of oil API values.[82]

The most recent figures from the U.S. Energy Information Administration showed that 91% of California's oil production in February of 2024 came from oil with an API gravity of 30 degrees or lower.[83] A 2009 report quotes Chevron as stating that "'[h]eavy oil makes up approximately 80 percent of the crude oil production in the California fields.'"[84] Similarly, a 2017 report from the Center for Biological Diversity found that "three-quarters of the state's current oil production is composed of very dirty crude that rivals Canada's tar sands crude and diluted bitumen in terms of its lifecycle greenhouse gas emissions and climate impacts."[85] This report also found that "[n]early two-thirds of remaining oil reserves in 18 of the largest oil fields in the San Joaquin and

[78] 17 Cal. Code Regs., § 95669(c)(2).
[79] Wood Memo at 2.
[80] California Energy Commission, Petroleum Watch (Feb. 2020), https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf
[81] Letter from Kyle Ferrar at 2.
[82] *Id.*
[83] U.S. Energy Information Administration, *Petroleum & Other Liquids*: *Crude Oil and Lease Condensate Production by API Gravity* (Released April 30, 2024),
[84] Communities for a Better Environment (CBE), *The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California and How to Clean them Up!* at 28 (2009), https://www.cbecal.org/wp-content/uploads/2012/05/wilmington_refineries_report.pdf?fbclid=IwZXh0bgNhZW0CMTAAAR1yssXK7gUeL6kJWxV39HEhroqOn2cKqYsleyQfpXm53fqWzy4LfiLNe68_aem_AdnFoe9mfJI2xzBwTabZsPHKZ3bVtwy76uJFVwiPMDgo6qAa44TSOSNEZhIiQFp3MUvW9I6sa63tZzh09Udsun1g.
[85] Shaye Wolf, PhD & Kassie Siegel, *Oil Stain: How Dirty Crude Undercuts California's Climate Progress*, Center for Biological Diversity (Nov. 2017), https://www.biologicaldiversity.org/programs/climate_law_institute/energy_and_global_warming/pdfs/Oil_Stain.pdf

Los Angeles Basins are also very dirty, totaling 6.1 billion barrels of particularly climate-damaging crude."[86]

Collectively, these estimates consistently show that the majority of oil production in California is heavy and that a loophole exempting heavy oil from RACT would swallow the rule, greatly reducing the efficacy of the SIP for VOCs. Not only is the majority of crude oil heavy, it accounts for a greater portion of extraction each year.[87]

According to a 2017 International Energy Agency survey, 96.5% of thermal enhanced oil recovery in the United States is performed in California.[88] In 2020, Kern County's Midway-Sunset oilfield produced more than 20 million barrels of oil.[89] Oil from this field is heavy crude. Chevron markets oil from Midway Sunset "at 13° API gravity and USGS records indicate gravities below 11° API."[90] Midway-Sunset is California's most productive field, despite its oils "grow[ing] heavier and more complex as it has aged, while air quality in the surrounding region constitutes the worst in the nation."[91] Midway Sunset "has [barrel-for-barrel] greenhouse gas (GHG) emissions that rival Canadian oil sands."[92]

California's second largest oilfield by volume is South Belridge in Kern County. It produced 18.4 million barrels of oil in 2020.[93] This oil is also heavy crude: "Crude from California's South Belridge field, north of Midway-Sunset, ha[d] an average API gravity of 15 degrees."[94] Kern County's Kern River and Cymric oil fields, produced 16.3 and 11.6 million barrels, respectively, in 2020. Each of these fields similarly require energy-intensive enhanced oil recovery to extract the heavy oil in the formations. Another large oilfield, Wilmington in Los Angeles County, produced 10.2 million barrels in 2020.[95] The Wilmington oilfield production relies heavily on waterflooding to extract the oil.[96] The Oil and Gas CTG estimated that the Los Angeles basin has the highest concentration of new wells per site, with the San Joaquin basin sixth on the list, and the Ventura Basin ranked at eleventh.[97]

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[86] *Id.*
[87] J. Fleming, *Killer Crude: How California Produces Some of the Dirtiest, Most Dangerous Oil in the World*, Center for Biological Diversity (June 2021), https://www.biologicaldiversity.org/programs/climate_law_institute/pdfs/June-2021-Killer-Crude-Rpt.pdf
[88] California Energy Commission, *Petroleum Watch* (Dec. 2021), https://www.energy.ca.gov/sites/default/files/2021-12/2021-12_Petroleum_Watch_ADA.pdf.
[89] CalGEM, Annual Oil and Gas Report – 2020 (2023), p. 13.
[90] Deborah Gordon & Samuel Wojcicki, *Drilling Down on Oil: The Case of California's Complex Midway Sunset Field*, Carnegie Endowment, Mar. 15, 2017, https://carnegieendowment.org/posts/2017/03/drilling-down-on-oil-the-case-of-californias-complex-midway-sunset-field?lang=en.
[91] *Id.*
[92] *Id.*
[93] CalGEM, 2020 Annual Report, p. 13.
[94] Judith Lewis Mernit, *Why Does Green California Pump the Dirtiest Oil in the U.S.?*, Yale Environment 360, Oct. 19, 2017, https://e360.yale.edu/features/why-does-green-california-pump-the-dirtiest-oil-in-the-u-s?fbclid=IwZXh0bgNhZW0CMTAAAR0dTBVjnyseUeJpKsneRWk-MqpaD9-_51lA-wFP0-jkpo9u13sjVpk2QNY_aem_AdmbEimNjJNPtV9WcaBtBnh0Qq71ujWVq9-qxI8PAshFawny-m4iWegSHiYPPIF_NttawVNptsoHcw36FyrGRmmC.
[95] CalGEM 2020 Annual Report, p. 13.
[96] CalGEM Annual Report 2020, p. 44.
[97] Oil and Gas CTG at 9-8 to -9.

Heavy oil resources "require more energy and water to produce and refine than lighter oils. They also contain sulfur and a range of polluting or toxic contaminants, including heavy metals, which must be removed and disposed of, further increasing costs and environmental impacts."[98] Heavy oils result in greater greenhouse gas emissions per barrel of oil produced, "especially due to gas-fired steam generators and the energy-intensive processing required to lighten or break down heavy oil into forms that can be transported and used."[99] For example, steam-injection produced heavy oil from the Midway Sunset field emits 725 kg CO2 per barrel, compared to 480 kg CO2 per barrel from "[t]ypical light West Texas oil."[100]

As heavy oil is difficult to access and process, California "extracts, refines, and burns some of the dirtiest oil on the planet."[101] For example, "[e]ach steam-injected well in Midway-Sunset requires the burning of natural gas to produce the necessary steam and lift the oil, which in some cases comes up freighted with as much as 95 times as much water as crude. Then, at the refining stage, producers use more natural gas to transform heavy crude into gasoline."[102] As a result, Midway-Sunset is "only one-and-a-half percent less carbon-intensive than tar sands oil from the Athabascan forests of Alberta."[103]

"Production of heavy oils…are known to produce secondary organic aerosols (SOAs) that make up fine particulate pollution ($PM_{2.5}$),"[104] which is tied to increased risk for cancer, diabetes and various lung and heart problems. A recent study found that production of Albertan oil sands is the leading source of air pollution in North America, emitting twice as much SOAs as car and truck exhaust."[105] As VOCs "are important precursors" to SOAs,[106] the link between SOAs and heavy oil further confirms that heavy oil is a major source of VOCs.

These extraction operations are a significant source of VOCs. A 2015 air quality monitoring study from the South Coast AQMD demonstrated that VOC emissions from oil and gas wells are

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[98] E. Allison & B. Mandler, *Heavy Oil: Abundant but hard to work with, heavy oil has some specific environmental impacts*, American Geosciences Institute, 2018, https://www.americangeosciences.org/sites/default/files/AGI_PE_HeavyOil_web_final.pdf.
[99] *Id.*
[100] *Id.*
[101] Judith Lewis Mernit, *Why Does Green California Pump the Dirtiest Oil in the U.S.?*, Yale Environment 360, Oct. 19, 2017, https://e360.yale.edu/features/why-does-green-california-pump-the-dirtiest-oil-in-the-u-s?fbclid=IwZXh0bgNhZW0CMTAAAR0dTBVjnyseUeJpKsneRWk-MqpaD9-_51lA-wFP0-jkpo9u13sjVpk2QNY_aem_AdmbEimNjJNPtV9WcaBtBnh0Qq71ujWVq9-qxI8PAshFawny-m4iWegSHiYPPIF_NttawVNptsoHcw36FyrGRmmC.
[102] *Id.*
[103] *Id.*
[104] Liggio, J. et al., Oil sands operations as a large source of secondary organic aerosols, Nature 534, 91-94 (2016), available at https://www.nature.com/articles/nature17646
[105] Gordon & Wojcicki, *supra* (citing John Liggio, et al., *Oil sands operations as a large source of secondary organic aerosols* (May 25, 2016), https://www.nature.com/articles/nature17646).
[106] Jookjantra, *Formation potential and source contribution of secondary organic aerosol from volatile organic compounds*, J. Envtl. Quality, at 1017. *See also id.* (identifying fuel evaporation and vehicle exhaust as major sources of VOCs contributing to SOAs), https://acsess.onlinelibrary.wiley.com/doi/epdf/10.1002/jeq2.20381.

considerably underestimated, and oil and gas wells actually contribute to more than half of the district's stationary source VOC emissions.[107]

Heavy oil wells are also located close to communities and raise serious environmental justice concerns. The Wilmington/Carson area of Southern California has "the highest concentration of refineries in California" including "heavy oil drilling in residential areas."[108] Many of California's heavy oil-producing fields "operate in densely populated areas, meaning that oil drilling occurs dangerously close to millions of Californians," including disproportionate drilling in "communities of color already suffering from severe environmental pollution."[109] Wilmington oil field contains heavy oil that relies largely on energy-intensive waterflood for extraction.

Many of the leaking wells identified in California over the past two years involved heavy oil, including heavy-oil wells operated by Sunray Petroleum, Inc in the HoodBloemer lease in the Morningstar neighborhood of Bakersfield, which community thermographers discovered in the spring of 2022.[110] The investigation of the Sunray wells led to the discovery of 49 additional leaking wells in the region—all of which "reported average API values of under 20°, and have therefore avoided detection," which "is often the issue" in California, due to deteriorating oil and gas infrastructure at heavy well sites.[111]

B. Absent RACT, widespread and extended VOC leaks are likely at heavy oil wells.

A SIP that only enforces RACT requirements for a small fraction of wells cannot meet the requirements of the Clean Air Act, which requires the inclusion of "enforceable emission limitations, and such other control measures means or techniques ... as may be necessary or appropriate to provide for attainment of such standard in such area by the applicable attainment date."[112]

For the same reasons discussed in Part I, above, the concern EPA demonstrated in its initial disapproval of portions of CARB's Oil and Gas Methane Rule applies equally to heavy oil wells.[113] Just like light-oil wells, heavy-oil wells have the potential to leak VOCs over extended periods of time. EPA specifically faulted the previous CARB Oil and Gas Methane Rule because it "did not capture all storage tanks in the oil and gas sector in the state that are required to meet RACT, the Rule allowed delay of leak repairs in several sections, and that there were several

[107] FluxSense, *Using Solar Occultation Flux and other Optical Remote Sensing Methods to measure VOC emissions from a variety of stationary sources in the South Coast Air Basin* at 3, 6 (Sept. 14, 2017), http://www.aqmd.gov/docs/default-source/fenceline_monitroing/project_2/fluxsense_project2_2015_final_report.pdf?sfvrsn=6.
[108] CBE, *supra*, at 3.
[109] CBD, supra, at 1.
[110] Letter from Kyle Ferrar at 3.
[111] *Id.*
[112] Clean Air Act, § 172(c)(6); 110(a)(2)(A)
[113] *See* 89 Fed. Reg. at 36732-33 (articulating concerns about prior versions of CARB's rules that allowed leaks to go undetected and/or unrepaired for unacceptable periods of time).

exemption in the Rule that reduced the Rule's stringency with respect to RACT."[114] The same concerns EPA raised for storage tanks exemptions applies even more to the vast number of wells that would be exempt under this SIP.

Failure to apply RACT inspection requirements to components used at heavy oil wells could allow leaks to continue indefinitely, thereby cancelling out the rationale for the exemption, even assuming heavy oil wells emit lower amounts of VOCs.[115] Neither the SIP nor the EPA has provided support that the exemption would not result in significant VOC emissions. On the contrary, an exemption that applies to heavy oil would effectively release the vast majority of oil wells from RACT requirements.

IV. EPA Must Revise Its Regulations To Require RACT at Wellhead-Only Sites.

For the same reasons discussed above, EPA's exemption from RACT for wellhead-only sites is illogical and inconsistent with the requirements of the Clean Air Act.[116] Wellhead-only sites are still subject to leaks, as such sites still contain at the very least a flanged casing hanger where a well can be shut-in with a flange seal and cap. The flange seals can fail due to aging or corrosion and deterioration. Casing hanger flanges have been a documented source of many leaks identified by community scientists using optical gas imaging (OGI) technology.[117] The Oil and Gas CTG recognizes that "[f]ugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate."[118] The same risk of deterioration is present at wellhead-only sites. In other words, wellhead-only sites still contain "fugitive emissions components," which EPA defines, in relevant part, as—

> any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not already subject to equipment and fugitive emissions monitoring, thief hatches or other openings on a controlled storage vessel, compressors, instruments and meters.[119]

Likewise, the same types of downhole risks that lead to leaks in other wells—such as casing age, proximity to wells used for cyclic steaming/steam flooding, etc.—are present at wellhead-only sites. The Oil and Gas CTG acknowledges that "[c]hanges in pressure, temperature, or mechanical stresses can also cause components or equipment to emit fugitive emissions."[120]

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[114] USEPA Region IX Technical Support Document for EPA Rulemaking, Cal. SIP, GHG Emission Standards for Crude Oil and Natural Gas Facilities. (Apr. 2024).
[115] *Cf.* 89 Fed. Reg. at 36735 (claiming "that monitoring for well sites producing heavy oils would not be sufficiently cost effective, as leaks associated with heavy oil production will generally emit less VOC").
[116] *See* Oil and Gas CTG at 9-1 (exempting sites that "only contain[] one or more wellheads").
[117] *See* Letter from Kyle Ferrar at 4, Appendix B (documenting leaking wellheads in the Bakersfield and Morningstar areas of Kern County in June 2022, including pictures indicating the location on the wellheads where the leaks occurred).
[118] *Id.* at 9-2.
[119] *Id.*
[120] *Id.*

Indeed, California's Geologic Energy Management Division treats wellhead-only sites as posing special concern, applying a presumption that a well has been deserted and must be plugged and abandoned in the interests of human health and the environment if the well's "production facilities or injection equipment has been removed from the well site for at least two years."[121] The State views deserted wells with no solvent operator as "public nuisances," deeming it "essential, in order to protect life, health, and natural resources that those oil and gas wells and facilities be abandoned, reabandoned, produced, or otherwise remedied to mitigate, minimize, or eliminate their danger to life, health, and natural resources."[122]

RACT requirements for wellhead-only sites could have prevented or mitigated the leaks discovered in Kern County, where many of the leaks came from wellheads not connected to any other equipment.[123]

V. Substantial evidence contradicts EPA's conclusion that RACT is economically infeasible.

EPA's economic feasibility evaluation is misplaced. RACT analyses are not subject to an economic analysis, and even if they were, the EPA's analysis in this instance does not support an exemption for heavy oil wells, wellhead only sites, or low production and idle wells.

As an initial matter, it is important to note that the Clean Air Act itself contains no economic feasibility caveat on the requirement for non-attainment states to utilize RACT. As regulated entities have no incentive to spend money to decrease their pollution in the absence of regulation, laws like the Clean Air Act should play a technology-forcing role to internalize the externality of air pollution. Moreover, economic analysis is, at best, an incomplete picture of the consequences of this SIP. At worst, it is misleading and obscures the true cost of pollution in ways that cannot be quantified into dollar amounts. The right to breathe healthy air or live on a sustainable planet is immeasurable and should not be weighed against the narrow pecuniary interests of the oil and gas industry.

Assuming *arguendo* that imposing an economic feasibility limitation on RACT is permissible under the Clean Air Act, the presumption still needs to be that readily available technology proven to reduce emissions *is* economically feasible. Here, RACT for VOCs is economically feasible at all well sites—whether idle, low producing, active, wellhead only, heavy-oil, or light oil—as RACT to detect leaks primarily involves operator-conducted inspections already in use by other sources in the source category (i.e., light-oil wells). Most importantly, benefits to human health and the environment from the additional reduction in VOCs will outweigh any added economic costs of more stringent regulation.

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[121] Cal. Pub. Res. Code, § 3237(a)(3)(B).
[122] Cal. Pub. Res. Code, § 3250.
[123] *See, e.g.,* Letter from Kyle Ferrar at 4, Appendix B (documenting wellhead leaks in the Bakersfield and Morningstar areas of Kern County in June 2022); CalGEM, *Well Inspections & Repair Updates* (last updated May 17, 2023) (discussing numerous leaks found between May 2022 and May 2023), https://www.conservation.ca.gov/well-inspections-repair-updates.

A. The Clean Air Act contains no exemption for economic infeasibility.

RACT is a technology-forcing standard designed to induce and require improvements in control technology and reductions in pollutant emissions.[124] The Clean Air Act itself does not contain a definition for "reasonably available control technology."[125] Indeed, EPA has long maintained that "RACT should represent the toughest controls considering technological and economic feasibility that can be applied to a specific situation" and that "[a]nything less than this is by definition less than RACT."[126] [127] "In determining RACT for an individual source or group of sources, the control agency, using the available guidance, should select the best available controls, deviating from those controls only where local conditions are such that they cannot be applied there and imposing even tougher controls where conditions allow."[128]

EPA first defined RACT in 1976 as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."[129] However, it has since been determined that the RACT standard does not require economic feasibility under the Clean Air Act.[130] The Clean Air Act "envisions situations where standards currently economically or technologically infeasible will nonetheless be enforced,"[131] and Clean Air Act requirements are "expressly designed to force regulated sources to develop pollution control devices that might at the time appear to be economically or technologically infeasible."[132] Further, "[t]he Supreme Court has held that neither the Administrator nor a reviewing court may reject a SIP on the ground that it is economically or technologically infeasible."[133] Thus, EPA should not approve any of the RACT exemptions described above even if inspections at some well sites are purported to be economically infeasible.

B. To the extent relevant, categorical operator adoption is a proper measure of economic feasibility rather than individual operator costs.

To the extent economic feasibility is relevant to the analysis, RACT for VOCs at all well sites is still economically feasible. Rather than attempting a complicated cost-benefit analysis, economic feasibility "considers the cost of reducing emissions and the difference in costs between the

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[124] Strelow Memo at 2; *see also Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 492 (2001) (Breyer, J., concurring) (noting that technology forcing requirements "are still paramount in today's [Clean Air] Act").
[125] CAA § 172(c)(1), 42 U.S.C. § 7502(c)(1).
[126] Strelow Memo at 2.
[127] *Thomas*, 805 F.2d at 180; *see* Strelow Memo at 2.
[128] *Id.* at 2.
[129] *Thomas*, 805 F.2d at 180; *see* Strelow Memo at 2.
[130] *See Nat'l Steel Corp., Great Lakes Steel Div. v. Gorsuch*, 700 F.2d 314 (6th Cir. 1983) (finding EPA's approval of SIP based on RACT determinations reasonable even though requirements appeared technologically and economically infeasible); *see also* 1 Environmental Law in Real Est. & Bus. Transactions § 5.02 (2024) N. 14 ("the term 'reasonably available' does not require economic feasibility for each individual source.").
[131] *United States v. Ford Motor Co.*, 814 F.2d 1099, 1103–04 (6th Cir. 1987) (quoting S.Rep. No. 91–1196, p. 2–3 (1970)) ("Congress has the authority to demand that 'existing sources of pollutants either should meet the standard of the law or be closed down....', regardless of whether such standards are currently feasible.").
[132] *Union Elec. Co. v. E.P.A.*, 427 U.S. 246, 257, 96 S. Ct. 2518, 2525, 49 L. Ed. 2d 474 (1976).
[133] *Gorsuch*, 700 F.2d at 324 (citing *Union Elec. Co. v. EPA*, 427 U.S. 246, 265, 96 S.Ct. 2518, 2529, 49 L.Ed.2d 474 (1976)).

particular source for which RACT is being determined and other similar sources that have implemented emission reductions."[134] EPA presumes that "similar sources . . . bear similar costs for emissions reduction."[135] In particular—

> Economic feasibility rests very little on the ability of a particular source to 'afford' to reduce emissions to the level of similar sources. Less efficient sources would be rewarded by having to bear lower emission reduction costs if affordability were given high consideration. *Rather, economic feasibility for RACT purposes is largely determined by evidence that other sources in a source category have in fact applied the control technology in question*.[136]

EPA stresses that "[t]he affordability of implementing a control option should generally not be considered in the economic impact analysis because affordability is highly subjective and depends upon the economic viability of a particular source."[137] Therefore, "control options should not be eliminated solely on the basis of economic parameters that indicate they are not affordable by the source."[138]

C. RACT for VOCs, including optical gas imaging or Method 21 inspections, is already in use at other wells in the source category.

It is economically feasible to require RACT such as optical gas imaging (OGI) and Method 21 inspections and monitoring at all well sites (including heavy oil wells, wellheads, and low production wells), as such technology is already required and in use at active, light-oil wells nationwide, and as California goes beyond EPA's minimum recommendations in the Oil and Gas CTG and currently requires OGI or Method 21 inspections and monitoring at low-production, light-oil wells.[139] Likewise, other states such as Colorado already have regulations requiring leak inspections "at all well sites."[140]

For RACT to be economically infeasible, an operator would need to "contend[] that it cannot afford RACT and/ or may have to shut-down its operation if RACT controls are imposed," potentially opening the door to an economic impact analysis "consist[ing] of weighing the

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[134] U.S. EPA, National Service Center for Environmental Publications, *Procedures for Identifying Reasonably Available Control Technology for Stationary Sources of PM-10*, EPA-452/R-93-001, at 2-6 (Sept. 1992).
[135] *Id.*
[136] EPA, State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 Fed. Reg. 18,070, 18,074 (Apr. 28, 1992).
[137] U.S. EPA, National Service Center for Environmental Publications, *Procedures for Identifying Reasonably Available Control Technology for Stationary Sources of PM-10*, EPA-452/R-93-001, at 2-7 (Sept. 1992); *see also* 87 Fed. Reg. 53381, 53390 (Aug. 31, 2022) ("EPA has long held that '[e]conomic feasibility rests very little on the ability of a particular source to `afford' to reduce emissions to the level of similar sources. Less efficient sources would be rewarded by having to bear lower emission reduction costs if affordability were given high consideration.'") (citing E.P.A., State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 FR 18,070, 18,073 (proposed April 28, 1992)).
[138] *Id*.
[139] Cal. Code Regs., tit. 17, §§ 95666, 95669(a), (c)(2).
[140] Oil and Gas CTG at 9-34.

benefits (and costs) of the facility remaining open against those of closing."[141] Even then, a standard will be economically feasible as long as it "will not be such as to threaten the financial welfare of the affected firms or the general economy."[142]

In light of California already requiring leak inspections at low-producing and idle wells, Colorado already requiring leak inspections at "all well sites," and EPA already requiring leak inspections at active, light-oil wells, it would be an abuse of discretion for EPA to conclude that mandating similar leak inspections at all well sites nationally would threaten the financial welfare of the industry or general economy as a whole.

Moreover, as the economic feasibility analysis "of a given RACT limit should reflect, to the extent possible, consideration of the past, current, and future expected operating environment,"[143] the notion that additional OGI inspections would "threaten the financial welfare" of the oil industry is particularly absurd. Operators continue their historic trend of raking in obscene profits[144] while under ongoing scrutiny for lying for years about the negative effects of drilling activities. California has sued five of the world's largest oil companies for "engaging in a decades-long campaign of deception and creating statewide climate change-related harms in California" in order "to further their record-breaking profits at the expense of our environment."[145] Such actions have resulted in California "spen[ding] tens of billions of dollars to adapt to climate change and address the damages climate change has caused so far," and anticipating the "need to spend multiples of that in the years to come."[146] EPA must follow the "polluter pays" principle to ensure that the oil industry—which can well afford to do so—employs every possible technology to prevent harmful leaks and emissions at all of their well sites, as the absolute minimum step necessary to start triaging the damage these operators have already done to our health and climate.

It is also notable that California oil production is on the decline overall, as more and more consumers make the switch to clean energy and operators take steps in anticipation of the State's transition to a carbon-neutral economy by 2045, meaning that any added inspection costs will be temporary and will likely decrease each year as the industry continues to phase down production

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[141] EPA, *Procedures for Identifying Reasonably Available Control Technology for Stationary Sources of PM-10* at 2-7-2-8 (Sept. 1992).
[142] 43 Fed. Reg. 5939 (Feb. 10, 1978). *See also Sierra Club v. Tahoe Regional Planning Agency*, 916 F. Supp. 2d 1098, 1124 (E.D. Cal. 2013) (stating in a state-law case that "[t]he fact that an alternative may be more expensive or less profitable is not sufficient to show that the alternative is financially infeasible. What is required is evidence that the additional costs or lost profitability are sufficiently severe as to render it impractical to proceed with the project." (quotation marks omitted)).
[143] 87 Fed. Reg. at 53383.
[144] *See* S. Reed, *Oil Giants Pump Their Way to Bumper Profits*, NY Times (Feb. 2, 2024) (noting that Exxon earned $36 billion in 2023 and Chevron earned $21.4 billion in 2023), https://www.nytimes.com/2024/02/02/business/oil-gas-companies-profits.html; S. Sadai, *Fossil Fuel Companies Make Billions in Profit as We Suffer Billions in Losses: 2024 Edition*, Union of Concerned Scientists (Apr. 17, 2024) (stating that "the combined profits of ExxonMobil, Chevron, Shell, and BP total[ed] over $100 billion" in 2023), https://blog.ucsusa.org/shaina-sadai/fossil-fuel-companies-make-billions-in-profit-as-we-suffer-billions-in-losses-2024-edition/.
[145] State of California, Department of Justice, *Attorney General Bonta Announces Lawsuit Against Oil and Gas Companies for Misleading Public About Climate Change*, Sept. 16, 2023, https://oag.ca.gov/news/press-releases/attorney-general-bonta-announces-lawsuit-against-oil-and-gas-companies.
[146] *Id.*

by plugging and abandoning more and more wells.[147] In fact, a study reviewing economically feasible methane mitigation strategies by sector determined that "the majority of economically feasible actions come from the oil and gas sector… oil and gas measures dominate the [potential] avoided warming from economically feasible actions."[148] Nevertheless, "[c]arbon emissions from the oil extraction process remained steady in California from 2000 to 2015, even as overall oil production fell by 30 percent over that same period," which means that the "carbon intensity"—and, thus, the health impact—of production has *increased*."[149]

RACT to address VOC emissions from *all* oil wells is necessary, readily available from a technological standpoint, and feasible for the oil industry to adopt.

D. The public health benefits of decreased VOCs—especially in frontline communities—far outweigh any RACT-related costs.

As discussed above, issues of individual-operator affordability should generally not come into play in RACT analysis. To the extent it is permissible to weigh costs and benefits under the Clean Air Act due to concerns about potential industry shutdowns, there is no doubt that the benefits of applying RACT to all wells outweigh any economic concerns.

Agencies "cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards."[150] Cost-benefit analyses can be "biased against regulations that benefit health, welfare, and safety" when "decision-makers give greater weight to effects that can be quantified" and "reject more stringent alternatives that achieve additional, non-monetized benefits that outweigh the additional costs."[151]

A recent American Lung Association report illustrates the proper way to value "health, welfare, and safety benefits" by documenting the widespread public health benefits from an accelerated transition away from fossil fuels to zero-emissions transportation. The report estimates $1.2 trillion in public health benefits across the U.S. by 2050, including $95.5 billion in benefits in the Los Angeles area, $42.5 billion in the San Francisco area, and $12.4 billion in the San Diego

[147] Executive Dept., State of Cal., Executive Order N-29-20 (Sept. 23, 2020), https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf.
[148] Ilissa Ocko et al, *Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming*, Environmental Research Letters, vol. 6, no. 5 (May 4, 2021), https://iopscience.iop.org/article/10.1088/1748-9326/abf9c8.
[149] K. Trout et al., *The Sky's Limit California: Why the Paris Climate Goals Demand that California Lead in a Managed Decline of Oil Extraction* at 17 (May 2018) (emphasis added), http://priceofoil.org/content/uploads/2018/05/Skys_Limit_California_Oil_Production_R2.pdf. *See also* Fleming, *supra*.
[150] *Center for Biological Diversity v. National Highway Traffic Safety Admin.*, 538 F.3d 1172, 1198 (9th Cir. 2008).
[151] Cal. Legislative Analyst's Office (LAO), Improving California's Regulatory Analysis (Feb. 2017) at 11-12 (based on a review by the California Legislative Analyst's Office of twenty-two different standard regulatory impact assessments from various state agencies), https://lao.ca.gov/reports/2017/3542/Improving-CA-Regulatory-Analysis-020317.pdf. For example, the LAO criticized the California Department of Resources Recycling and Recovery's SRIA for the Compostable Materials regulation, because it "did not quantify the environmental benefits of any of the options it considered." *Id.* at 12-13.

area.[152] The cumulative health benefits in these regions also include avoiding nearly 14,000 premature deaths, over 383,000 asthma attacks, and over 1.9 million workdays lost due to cleaner air.[153]

As noted above, ozone is a major contributor to asthma. According to the Centers for Disease Control and Prevention (CDC), in 2021 California was the state with the highest number of deaths caused by asthma, totaling 352 deaths that year.[154]

Similarly, an expert report examining just the health benefits related to reduced exposure to PM2.5 with a 3,200-foot setback between sensitive receptors and oil and gas wells showed a health benefit of somewhere between $500 million and $828 million annually due to a decline in premature mortality.[155] According to a CARB estimate, if PM2.5 were "reduced to background levels," each year around 7,200 premature deaths, 1,900 hospitalizations, and 5,200 emergency room visits would be avoided.[156] As discussed above, heavy oil fields underly the many oil wells interspersed throughout populated regions in California—especially the Los Angeles area and Kern County—illustrating that RACT leading to early leak detection and prompt leak repairs at heavy oil wells will result in substantial cost savings from a public health standpoint. Similarly, low-producing and idle wells, and isolated wellheads are prevalent in frontline communities.

VI. California's SIP Does Not Require Sufficiently Frequent Monitoring and Reporting To Qualify As RACT.

A. Monitoring Frequency and Methodology

Federally, the Oil and Gas CTG only recommends semiannual monitoring of wells, using OGI or Method 21 at a detection frequency of 500 ppm.[157] At the state level, CARB's rules require quarterly emissions monitoring of wells using Method 21, with a detection frequency of 1,000 ppm.[158] Both the federal guidelines and the state rules do not go far enough toward achieving RACT in terms of the monitoring frequency and degree of technological sensitivity needed to promptly detect and stop VOCs emissions, for three reasons.

First, to the extent California utilizes a Method 21 detection frequency of 1,000 ppm, this frequency is inconsistent with the CTG and must be changed. Even 500 ppm is a relatively high threshold, considering "a typical handheld camera can accurately detect emissions at

[152] Am. Lung Assn., *Zeroing in on Healthy Air* at 3, 12 (2022), https://www.lung.org/getmedia/13248145-06f0-4e35-b79b-6dfacfd29a71/zeroing-in-on-healthy-air-report-2022.pdf.
[153] *Id.* at 12.
[154] Centers for Disease Control and Prevention, *Most Recent Asthma State or Territory Data*, https://www.cdc.gov/asthma/most_recent_data_states.htm (last visited May 31, 2024).
[155] James Bono, et al., *Recommendations to CalGEM for Assessing the Economic Value of Social Benefits from a 3,200' Buffer Zone Between Oil & Gas Extraction Activities and Nearby Communities* at 14-16 (Dec. 2021).
[156] California Air Resources Board, *Health & Air Pollution*, https://ww2.arb.ca.gov/resources/health-air-pollution (last visited May 31, 2024).
[157] Oil and Gas CTG at 3-7 to -8.
[158] Cal. Code Regs. tit. 17, § 95669.

concentrations of down to 20 ppm" and "[e]ven an off-the shelf Klein methane detector costing just $100 at Home Depot has a detection limit near 50 ppm."[159]

Second, the increased frequency at use in California illustrates that such standards are technologically possible and, to the extent relevant, economically feasible. Even so, monthly emissions monitoring would be much more protective of human health and the environment. The Oil and Gas CTG agrees. For example, the CTG estimates an additional 20 percent in VOC emissions reductions with monthly monitoring compared to quarterly monitoring with OGI inspections.[160] Data also shows better emissions reduction with more frequent inspections using Method 21.[161] Frequent inspections facilitate prompt repair, which can have a huge impact. In fact, one study showed that repairing leaks reduced emissions by about 8,400 metric tons methane.[162] As discussed *infra*, the Clean Air Act's standards are "expressly designed to force regulated sources to develop pollution control devices that might at the time appear to be economically or technologically infeasible,"[163] and any cost increase related to monthly monitoring can and should be absorbed by the oil industry. Like the heavy oil exemption, the low monitoring frequency recommended in the Oil and Gas CTG is a non-binding guidance that California-specific information warrants reconsidering here.[164]

Third, California's SIP would allow a decrease in monitoring frequency if a well had no violations for five quarters.[165] This is based on a logical fallacy—the supposition that a lack of leaks in the past is an indicator that there will be no leaks in the future. In reality, the entirety of the discussion about the frequency of VOC leaks from oil wells underscores the need for to maintain constant vigilance, regardless of whether a particular well has a history of leaks in the recent past.

B. Reporting Frequency

The oil and gas RACT provisions are unenforceable, in violation of the Clean Air Act, because they lack adequate reporting requirements. Without timely reporting requirements that parallel the necessary monitoring frequency discussed above, enforcement agencies and members of the public cannot gauge the industry's compliance with RACT. EPA has rejected other SIPs because their lax reporting requirements hindered the state and local residents from accessing the information needed to enforce the provision of the SIP.[166]

[159] Letter from Kyle Ferrar at 2.
[160] Oil and Gas CTG at 9-20.
[161] *Id.* at 9-21 to -22.
[162] Lucy Cheadle et al., *Leak detection and repair data from California's oil and gas methane regulation show decrease in leaks over two years*, Environmental Challenges at 5 (2022), https://www.sciencedirect.com/science/article/pii/S2667010022001202.
[163] *Union Elec. Co. v. E.P.A.*, 427 U.S. 246, 257 (1976).
[164] Wood Memo at 2.
[165] EPA, *TSD for EPA's Rulemaking for the California State Implementation Plan* at 9 (April 2022).
[166] *See, e.g.,* 88 Fed. Reg. 29827 (May 9, 2023) (disapproving Colorado SIP that only requires operators to maintain records)

Emission limitations under the Clean Air Act must be enforceable.[167] Without a mechanism to evaluate compliance, enforcement is impossible. Courts have previously granted petitions for review based on EPA's failure to explain how it could ensure compliance with a Clean Air Act requirement without requiring that the relevant data be recorded and reported.[168]

While California's SIP requires *some* degree of reporting, the annual reporting timeline is insufficient.[169] As discussed above, in initially disproving portions of California's air rules, EPA expressed concern that the wording could have facilitated extended leakage from wells prior to detection and/or delayed repair timelines, thereby contributing to the problem of ozone pollution rather than combating it. Without timely reporting, there is an inability "for public insight into how the plants are operating, and therefore no way for interested members of the public, or more crucially, the EPA itself, to conduct oversight."

Similarly, with limited oversight other than annual reporting, there is the potential for an operator to be aware of leaks and not fix the issue for extended time periods, or for an operator to choose not to conduct inspections for a year and deal with the consequences. Due to historically low bonding, California has dealt with many instances of operators deliberately deserting their wells and rejecting their regulatory obligations in favor of bankruptcy.[170]

Under the annual reporting requirements of California's SIP, it is possible for a well to be leaking fugitive emissions of VOCs for an entire year before regulators or members of the public learn about the issue. Annual reporting thus defeats the purpose of RACT overall—to help states come into attainment by decreasing source emissions—and cancels out the prompt-detection-and-repair rationale for requiring more frequent inspections in the first place.

VII. Conclusion

Together, the heavy oil exemption in the Oil and Gas CTG and SIP, the CTG's low-production exemption, and the wellhead-only exemption codified in EPA's regulations, and California's monitoring and reporting practices create exemptions that swallow the RACT rule for monitoring and reducing fugitive emissions from oil and gas wells. In other words, "[w]hile the reasoning supporting each element is questionable individually, joined together they are decidedly worse than the sum of their parts."[171]

Californians, especially those in environmental justice communities, have suffered from poor air quality for far too long. Oil and gas activity is a major reason why residents are unable to breathe

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[167] *See* 42 U.S.C. § 7502(c)(6); *Ass'n of Irritated Residents v. EPA*, 686 F.3d 668, 677-78 (9th Cir. 2012) (finding EPA approval of an unenforceable, discretionary plan element arbitrary and capricious).
[168] *See New York v. EPA*, 413 F.3d 3, 35-36 (D.C. Cir. 2005) (remanding to EPA so that the agency could either provide an acceptable explanation for its "reasonable possibility" standard or to devise an appropriately supported alternative).
[169] Cal. Code Regs. tit. 17, § 95673(a)(12).
[170] Kyle Ferrar, *Literally Millions of Failing Abandoned Wells*, FracTracker Alliance, Mar. 29, 2019, https://www.fractracker.org/2019/03/failing-abandoned-wells/. *See also Sierra Club,* 972 F.3d at 308 (acknowledging "under the CAA, [that] past practices of weighing economic factors have historically counseled against complete compliance").
[171] S*ierra Club*, 972 F.3d at 299.

healthy air. EPA has the legal duty to ensure that states are meeting the requirements of the Clean Air Act by imposing effective measures to reduce pollution. California's SIP fails to do so and must be rejected with instructions to the state to resubmit a plan that properly covers all well sites and incorporates environmental justice goals in its analysis. Likewise, EPA must revise the Oil and Gas CTG and the wellhead-only exemption in EPA's regulations implementing the Clean Air Act to ensure RACT is properly in use at all well sites nationally.

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Heavy Oil

Abundant but hard to work with, heavy oil has some specific environmental impacts

Introduction

Naturally occurring crude oil comes in many forms. The most familiar to many people is light crude oil, which is less dense than water and flows easily at room temperature. Heavy oil and bitumen are forms of crude oil that are more viscous (thicker) and dense. The largest crude oil deposits in the world are heavy oil, extra-heavy oil, and bitumen oil sands (also called tar sands) in Venezuela and Canada. The U.S. also has heavy oil and oil sands, mostly in California, Alaska, and Utah. Globally, almost 1.1 trillion barrels of heavy oil, extra-heavy oil, and natural bitumen may be technically recoverable, compared to 950 billion barrels of light crude oil.[1]

Vast heavy oil resources pose an environmental conundrum: they are major energy resources and important to their host countries' economies, but they require more energy and water to produce and refine than lighter oils. They also contain sulfur and a range of polluting or toxic contaminants, including heavy metals, which must be removed and disposed of, further increasing costs and environmental impacts.[1,2]

Production Techniques

Because heavy oils are very viscous, they are difficult to extract from rocks. Different techniques are used depending on the type of oil and the properties and depth of the rocks:

Oil sand from Athabasca, Canada. The oil in these sands is so thick (viscous) that special processing is required to separate it from the sand. Image credit: Wikimedia Commons user Int23.[3]

- **Open-pit mining** – used for oil sands that are very close to the Earth's surface (typically less than 250 feet deep). The oil sands are mined in bulk, crushed, and transported to processing facilities that separate the oil from the sand using hot water and/or solvents. The ultra-thick oil (bitumen) is then refined or diluted with light oil for pipeline transport.[4] Open-pit mining is used for about 20% of Canadian oil sand production.[4] The Uinta basin in Utah also contains large, shallow oil sand deposits, but many efforts to produce oil from these sands have failed commercially.[5]

- **Injection of water, steam, and/or solvents** – used where heavy oil is deep below the surface, or where surface mining is not viable for environmental or commercial reasons. **Waterflooding** – the injection of water through one well to push oil towards another well where it is extracted – has been used to produce over 100 million barrels of heavy oil in Alaska since the early 1990s.[5] **Steam flooding** works in the same way, but the steam's heat softens the oil, allowing the process to be used for more viscous oils than waterflooding. This method is used in central California[6] and parts of Alberta. A special steam injection method called **steam-assisted gravity drainage (SAGD)** is used for 80% of Canadian oil sand production. SAGD involves the injection of steam into a horizontal well at the top of the oil sands. The heated and thinned oil then drains down into another horizontal well at the base of the oil sands, which then pumps the oil to the surface.[4] Any of these processes may be enhanced by adding solvents to the water.

- **Cold heavy oil production with sand (CHOPS)**[7] – used for mushy heavy and extra-heavy oil sands that can be extracted in their entirety through a well using intensive pumping. The oil, water, and sand are then separated at the surface. This technique has been tested in oilfields in Alaska's North Slope but not yet commercially developed due to low oil prices.[5]

Environmental Impacts Specific to Heavy Oil

Energy – heavy oils require much more energy to produce and refine than light crude oil. This leads to higher overall greenhouse gas emissions per barrel of oil produced, especially due to gas-fired steam generators and the energy-intensive processing required to lighten or break down heavy oil into forms that can be transported and used. Total "lifecycle emissions" from production, refining, transportation, and use for light vs. various heavy oils are:[8]

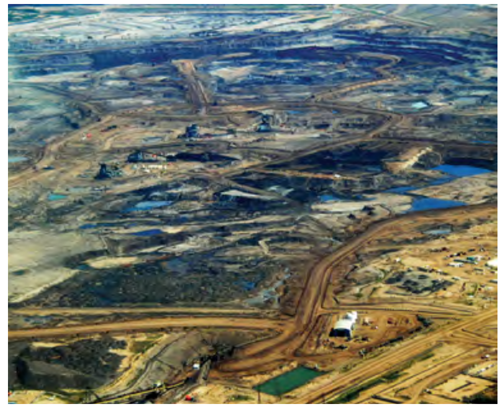
- Typical light West Texas oil - 480 kg CO_2 per barrel
- Canadian oil sands bitumen produced by SAGD, and Venezuelan extra-heavy oil, both diluted with lighter oil for ease of transport – 600 kg CO_2 per barrel
- Heavy oil produced by steam injection in California's Midway Sunset field - 725 kg CO_2 per barrel
- Canadian oil sands produced by open-pit mining and upgraded to a light synthetic crude oil ("syncrude") before transporting – 729 to 736 kg CO_2 per barrel

Open pits – open-pit mining of oil sands poses some specific environmental challenges that are less common elsewhere in the oil industry:

- Large volumes of tailings (residual clay, bitumen, and other chemicals) are stored in open surface ponds, presenting a potential risk to wildlife[9] and groundwater.[10,11]
- Tailings ponds, piles, and exposed heavy oil in the open mine, along with the heavy industrial activity common to all mining operations, are a major source of air pollution,[12] and dust from the mines can contaminate nearby surface waterbodies.[9]
- Open-pit mining of oil sands disturbs more of the land surface than oil wells. This impact is temporary if the mine land is fully reclaimed after the oil sands are extracted (as is currently required by the Government of Alberta, Canada), but has the effect of fragmenting or destroying habitats.[13]

Consistency of Heavy Oils

Heavy oil - like molasses
Extra-heavy oil – like peanut butter
Oil in oil sand – like window-sealing caulk or putty



Open-pit mining of oil sands in Alberta, Canada. The ponds in the photo are "tailings ponds", containing a mixture of water, fine sand, clay, and residual oil components after the sands have been processed to remove most of the oil. Image Credit: Dru Oja Jay, Dominion.[14]

U.S. Imports of Heavy Oil

The United States is the largest consumer of Canadian and Venezuelan heavy oil, extra-heavy oil, and bitumen. In 2017, the United States imported 2.7 million barrels of heavy oil per day from Canada[15] and 618,000 barrels per day from Venezuela.[16] Heavy oil imports from these two countries represented over 40% of U.S. crude oil imports in 2016.[16]

References & More Resources

For a complete listing of references, see the "References" section of the full publication, *Petroleum and the Environment*, or visit the online version at: www.americangeosciences.org/critical-issues/petroleum-environment

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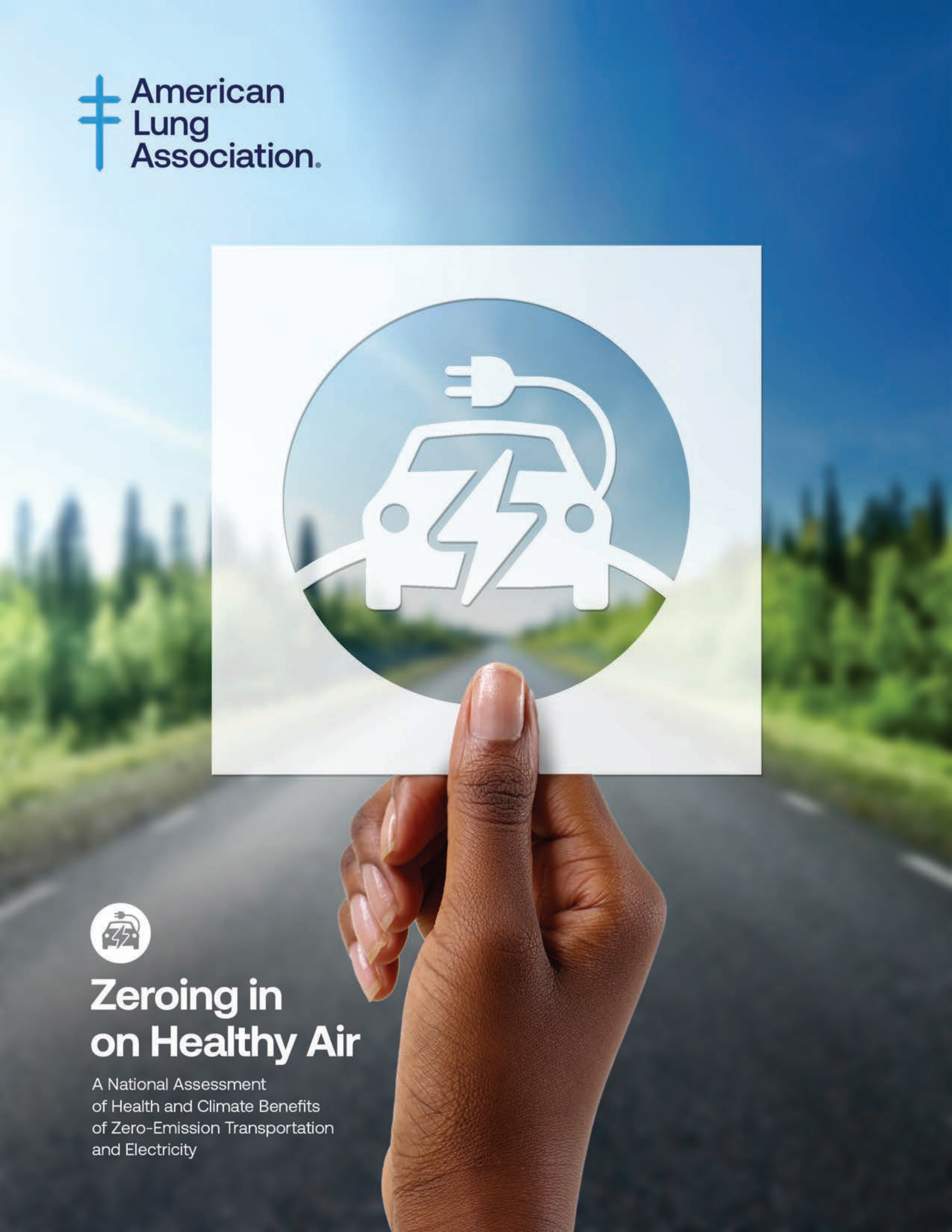
Carnegie Endowment for International Peace – Oil-Climate Index: Profiling Emissions in the Supply Chain. http://oci.carnegieendowment.org/#supply-chain



American Lung Association.

Zeroing in on Healthy Air

A National Assessment of Health and Climate Benefits of Zero-Emission Transportation and Electricity

About this Report

Zeroing in on Healthy Air finds that a widespread transition to zero-emission cars, trucks, buses and other vehicles, coupled with non-combustion, renewable energy resources would yield tremendous air quality, public health and climate benefits across the United States. To illustrate the potential benefits, a transition to 100 percent sales of light-duty passenger vehicles and medium-and heavy-duty vehicles were assumed over the coming decades, along with a transition to non-combustion electricity generation.

Zeroing in on Healthy Air builds off the 2020 Road to Clean Air report by the American Lung Association, and illustrates the potential scale of benefits to public health, air quality and climate change if the United States accelerates the course to a zero-emission transportation sector coupled with non-combustion renewable sources like wind and solar energy. While similar to the 2020 "Road to Clean Air" report on zero-emission transportation, this report stands alone. Updates to technical models, assumptions and methods do not allow for direct comparisons between "Road to Clean Air" and this new analysis.

The American Lung Association developed this project with the assistance and technical support of ICF Incorporated, LLC (ICF). Using a series of modeling tools, ICF provided estimated fleet characteristics and emissions profiles (US EPA MOVES2021 model, ICF's custom fleet modeling), emissions associated with fuel and electricity generation (Argonne National Lab GREET Model, ICF's custom IPM model) and health outcomes associated with changes in emissions (US EPA COBRA health model). ICF conducted a comprehensive analysis of the potential health and climate benefits of this transition as a consultant to the American Lung Association, which is solely responsible for the content this report. Additional details on the structure of the report, a full methodology and assumptions about future vehicle fleets, changes in the electric power grid and citations are detailed in the technical report document prepared by ICF for the American Lung Association. Available online at Lung.org/ev.

Contents

Executive Summary

Zeroing in on Healthy Air is a report by the American Lung Association illustrating the public health urgency of policies and investments for transitioning to zero-emission transportation and electricity generation in the coming decades. These sectors are leading sources of unhealthy air in the United States. Today, over four in ten Americans — more than 135 million people — live in communities impacted by unhealthy levels of air pollution. Research demonstrates that the burdens of unhealthy air include increased asthma attacks, heart attacks and strokes, lung cancer and premature death. These poor health outcomes are not shared equitably, with many communities of color and lower income communities at greater risk due to increased exposure to transportation pollution. The transportation sector is also the largest source of greenhouse gas emissions that drive climate change, which threatens clean air progress and amplifies a wide range of health risks and disparities.

This report finds that a national shift to 100 percent sales of zero-emission passenger vehicles (by 2035) and medium- and heavy-duty trucks (by 2040), coupled with renewable electricity would generate over $1.2 trillion in public health benefits between 2020 and 2050. These benefits would take the form of avoiding up to 110,000 premature deaths, along with nearly 3 million asthma attacks and over 13 million workdays lost due to cleaner air. This report calculates the emission reductions possible from shifting to vehicles without tailpipes, as well as eliminating fuel combustion from the electricity generation sector so that neither those living near roads or near electricity generation would be subjected to unacceptable doses of toxic air pollution. The report also highlights the fact that the shift to zero-emission transportation and electricity generation in the United States will yield avoided global climate damages over $1.7 trillion.

By expediting investments and policies at the local, state and federal levels to reduce harmful pollution, all communities stand to experience cleaner air. Policies and investments must prioritize low-income communities and communities of color that bear a disproportionate pollution burden. State and local jurisdictions should act to implement policies as soon as possible, including in advance of the benchmarks used in this report's methodology. These actions are needed to achieve clean air, reduce health disparities and avoid even more dire consequences of climate change.

Zeroing in on Healthy Air

In the United States, transportation and electricity generation are leading sources of unhealthy air and the pollutants that cause climate change.

Those living near highways, ports, railyards, warehouses, and other transportation hubs are at greater health risk, as are those impacted by fuel refining, electricity generation and processes.

The widespread, rapid shift to zero-emission transportation and electricity generation is critical to healthy air, and can yield more than $1.2 trillion in health benefits and 110,000 pollution-related deaths avoided over the coming decades along with over $1.7 trillion in global climate benefits.

The Public Health Need for Zero Emissions

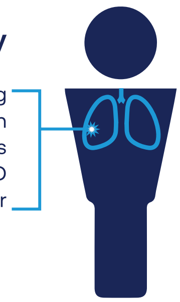
Air Pollution Remains a Major Threat to Americans' Health

Despite decades of progress to clean the air, more than 4 in 10 of all Americans — 135 million — still live in a community impacted by unhealthy levels of air pollution.[ii] Those impacted by polluted air face increased risk of a wide range of poor health outcomes as the result of increased ozone and/or particle pollution.[iii] The adverse impacts of pollution from the transportation and electricity generation sectors are clear, and must be recognized as a threat to local community health, health equity and a driver of major climate change-related health risks. Even with certification to meet existing standards, it is clear that combustion technologies often generate far greater levels of pollution in the real world than on paper.

Air pollution can harm children and adults in many ways

Respiratory

- Wheezing and coughing
- Shortness of breath
- Asthma attacks
- Worsening COPD
- Lung cancer

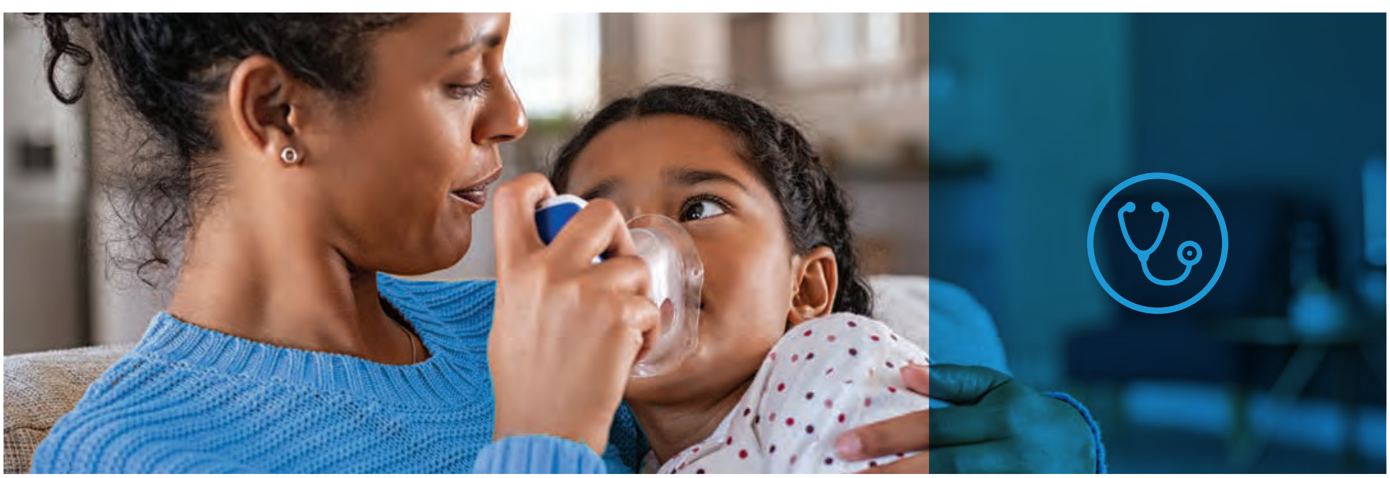


Other

- Premature death
- Susceptibility to infections
- Heart attacks and strokes
- Impaired cognitive functioning
- Metabolic disorders
- Preterm births and low birth weight

"The shift to zero-emission transportation and electricity generation will save lives and generate massive health benefits across the United States. It is critical that we ensure these benefits are realized in the near term in communities most impacted by harmful pollution today."

Harold Wimmer, American Lung Association President and CEO



Location Matters: Disparities in Exposure Burden

Exposure to pollution with its associated negative health consequences is dictated by where someone lives, attends school or works. In general, the higher the exposure, the greater the risk of harm. Many communities face disproportionate burdens due to pollution generated from production, transportation, refining and combustion of fuels along the transportation and electricity generating systems. Lower income communities and communities of color are often the most over-burdened by pollution sources today[iv] due to decades of inequitable land use decisions and systemic racism.

The American Lung Association's State of the Air 2021 report illustrated the disparities in pollution burdens across the United States, noting that a person of color in the United States is up to three times more likely to be breathing the most polluted air than white people.[v] All sources of harmful air and climate pollution must shift rapidly away from combustion and toward zero-emission technologies to ensure all Americans have access to the benefits of less-polluting technologies.

"Pollution from the transportation sector has been a long-standing obstacle to advancing environmental justice, as many communities of color and low-income families live near areas where pollution from vehicles and engines is abundant, and therefore experience disproportionate exposures to this pollution."

US EPA
Transportation and Environmental Justice
Fact Sheet March 2022

"Rapidly eliminating emissions from the transportation and electricity generation sectors must be a national priority. The nationwide transition to electric vehicles is urgently needed to improve lung health and advance health equity."

Harold Wimmer
American Lung Association President and CEO

For those living in close proximity to major transportation hubs like highways, ports, railyards or warehouses, tailpipe (or "downstream") emissions yield an outsized risk to community health.

Similarly, "upstream" emissions from transportation fuels generate localized health burdens near oil and gas extraction sites, refineries and even local gas stations, all of which generate toxic air pollution and threaten community health.

Health of communities all along the electricity production system — from the extraction of fossil fuels such as coal, oil and gas, transportation of these fuels, and combustion at the power plant itself — can be adversely impacted.

Estimated Benefits of Zero-Emission Transportation and Electricity Generation

The combustion of fuels in the electricity generation and transportation sectors is a major contributor to the health and climate burdens facing all Americans. These sources of pollution also create significant disparities in pollution burdens and poor health, especially in lower-income communities and communities of color. The transition to non-combustion technologies is underway and must continue to accelerate to protect the health of communities today and across the coming decades. Key findings are presented below:

Pollution Reduction Benefits from Zero-Emission Transportation

Accelerating the shift to zero-emission transportation and non-combustion electricity generation will generate major reductions in harmful pollutants. Key pollutants included in this research are described below along with projected on-road pollution reductions with the shift to zero-emission technologies when compared with a modeled "Business As Usual" case for the on-road fleet.

Pollutant	Impact	On-Road Pollution Reductions by Year		
		2030	2040	2050
Nitrogen Oxides (NOx)	NOx and VOCs are building blocks for ozone ("smog") and contribute to particle pollution formation and a wide range of health impacts including asthma attacks, heart attacks, strokes, and premature death. Breathing VOCs can irritate the eyes, nose and throat, can cause difficulty breathing and nausea, and can damage the central nervous system as well as other organs. Some VOCs can cause cancer. NO2 is associated with increased risk of asthma attacks, ER visits, hospitalizations and a range of other health consequences.	-6% ↓	-56% ↓	-92% ↓
Volatile Organic Compounds (VOC)		-8% ↓	-42% ↓	-78% ↓
Fine Particle Pollution (PM2.5)	Particle pollution can increase the risk of heart disease, lung cancer and asthma attacks and can interfere with the growth and work of the lungs. Major health impacts include asthma attacks, heart attacks, stroke, COPD, lung cancer and death.	-8% ↓	-43% ↓	-61% ↓
Sulfur Dioxide (SO2)	Contributes to wheezing, shortness of breath and chest tightness, reduced lung function, increased risk of hospital admissions or emergency room visits.	-15% ↓	-67% ↓	-93% ↓
Greenhouse Gases (GHG)	Drives climate change health risks, including extreme weather, wildfires and degraded air quality among others.	-14% ↓	-66% ↓	-93% ↓

Benefits of Moving All Vehicle Classes to Zero-Emissions

All vehicles must move to zero-emission technologies to ensure the most robust public health benefits occur. The 2020 passenger vehicle fleet represents approximately 94 percent of the nation's on-road vehicle fleet and generates over 1 million tons of ozone- and particle-forming NOx emissions, and over 33,400 tons of fine particles annually. Heavy-duty vehicles represent approximately six percent of the on-road fleet in 2020, but generate 59 percent of ozone- and particle-forming NOx emissions and 55 percent of the particle pollution (including brake and tire particles).

Differentiating the relative impacts of fleet segments is particularly important when considering the concentrations of heavy-duty vehicles in environmental justice areas near highways, ports, railyards and warehouse settings. For greenhouse gases (GHG), the 2020 light duty vehicle fleet generates approximately 69 percent of GHG emissions, while the heavy-duty fleet produces 31 percent.

The table below illustrates the relative emission reduction benefits of on-road transportation electrification for each the light-duty fleet and the medium- and heavy-duty segments compared with the "Business-As-Usual" case. It is important to note that these on-road reductions could yield major benefits within each class, with light-duty vehicles reducing nearly twice the GHGs as heavy-duty, while heavy-duty engines could yield approximately eight times the smog- and particle-forming NOx emissions when compared with the light-duty fleet. Ultimately, all segments produce harmful pollutants and must move quickly to zero-emissions to protect health and reduce climate pollution.

Pollutant	**Light Duty:** On-Road Emission Reductions (Tons per Year, Percent Reduction)			**Heavy Duty:** On-Road Emission Reductions (Tons per Year, Percent Reduction)		
	2030	**2040**	**2050**	**2030**	**2040**	**2050**
Nitrogen Oxides	-23,124 **-8%**	-80,975 **-61%**	-111,168 **-92%**	-51,274 **-6%**	-478,879 **-55%**	-887,640 **-92%**
Volatile Organic Compounds	-49,080 **-9%**	-195,520 **-41%**	-347,094 **-76%**	-4,316 **-5%**	-41,379 **-51%**	-80,375 **-87%**
Fine Particles	-2,903 **-10%**	-11,369 **-42%**	-16,170 **-58%**	-644 **-4%**	-5,737 **-43%**	-9,682 **-68%**
Greenhouse Gases (CO2e, Short Tons)	-198 M **-18%**	-733 M **-70%**	-1.0 B **-94%**	-37 M **-7%**	-322 M **-58%**	-572 M **-92%**

National Results: Public Health and Climate Benefits

The shift to zero-emission transportation and non-combustion electricity generation could yield major health benefits throughout the nation in the coming decades. Cumulatively, the national benefits of transitioning away from combustion in the transportation sector toward 100 percent zero-emission sales and a non-combustion electricity generation sector could generate over $1.2 trillion in health benefits across the United States between 2020 and 2050. These benefits include approximately 110,000 lives saved, over 2.7 million asthma attacks avoided (among those aged 6-18 years), 13.4 million lost works days and a wider range of other negative health impacts avoided due to cleaner air.[1,2] IIn addition to these health benefits, this analysis found that over $1.7 trillion in global climate benefits could be achieved with a reduction of over 24 billion metric tons of GHGs by mid-century.[3]

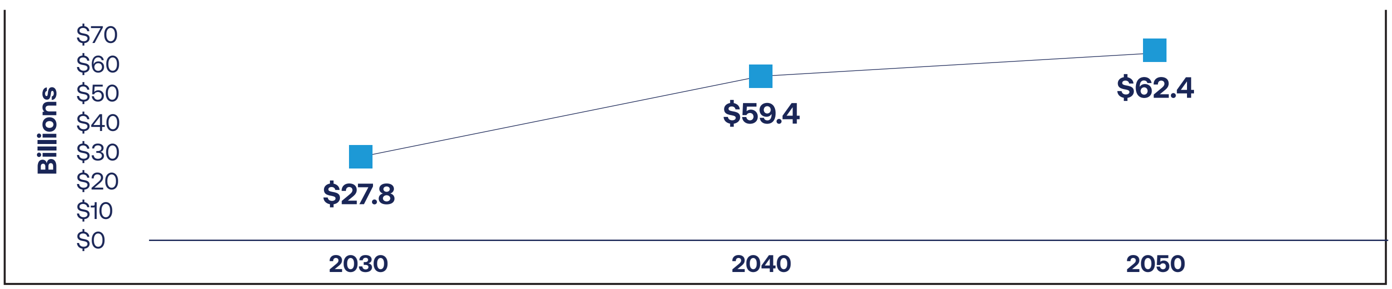
National Scale Benefits to Health and Climate (Cumulative: 2020-2050)

Public Health Benefits 2020-2050			Value of Benefits 2020-2050	
Premature Deaths Avoided	Asthma Attacks Avoided	Lost Work Days Avoided	Public Health Benefits	Climate Benefits
110,000	2.78 M	13.4 M	$1.2 T	$1.7 T

Near-Term Health Benefits

While the benefits noted above are cumulative between 2020 and 2050, this analysis also finds that annual health benefits could reach into the tens of billions by the end of this decade – nearly $28 billion in 2030 alone. Health benefits increase significantly as deployments of zero-emission technologies in the transportation and electricity generating sectors expand.

Annual Health Benefits (Billions)



Note: Total values presented for all vehicles using high estimate of benefits using a 3% discount rate and using 2017$.

[1] Note that the analysis and report include ozone-precursor emissions data. However, ozone-related health effects are not included in this report. US EPA's COBRA model relies on PM2.5 health effects to assess and monetize impacts. Results therefore do not include significant health burdens posed by ozone pollution throughout the United States independent of those related to PM reductions, as described in the health effects section of this report.

[2] In all cases, avoided health costs are presented in 2017 dollars. The value of avoided mortality estimates is grown from EPA's 1990 value of a statistical life to future years using standard income growth data and are presented in 2017 dollars. These results reflect the benefits of cumulative emission reductions estimated between 2020 and 2050, utilizing the American Lung Association's on-road and upstream emissions scenarios. Health results include the number of avoided adverse health impacts and the economic value of these health risk reductions at a 3% discount rate and reflect higher range estimates associated with the Di et al. (2017) health study. Greenhouse gas emission benefits are based on interim SCC values published in February 2021 by the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government.; climate benefits are also presented in 2017$ values at a 3 percent discount rate.

[3] The social cost of CO2 emissions (SC-CO2) is a measure, in dollars, of the long-term damage done by a ton of carbon dioxide (CO2) emissions in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e., the benefit of a CO2 reduction). SC-CO2 is intended to be a comprehensive estimate of climate change damages and includes changes in net agricultural productivity, human health, property damages from increased flood risk, and value of ecosystem services. However, not all important damages are included due to data limitations. Note that the climate change benefits of clean electricity generation are limited to the transportation-driven marginal increases in emissions, and do not include all benefits from the entire grid shifting to non-combustion sources, which differs from the whole-grid approach to air pollutants.

State Results: Public Health Benefits Across the United States

Every state in the U.S. stands to experience significant public health benefits from the widespread implementation of zero-emission transportation and electricity resources over the coming decades. As shown below, more than half of the states could experience more than $10 billion in cumulative public health benefits. Two states (California and Texas) could exceed $100 billion in health benefits, and six more states (Pennsylvania, Florida, Ohio, New York, Illinois, and Michigan) could see benefits exceeding $50 billion by 2050. These benefits cover a wide range of avoided health impacts, three of which (premature deaths, asthma attacks, lost workdays) are shown in the table below.

State	Cumulative Health Benefits, 2020 - 2050			
	Health Benefits (Billions)	Premature Deaths Avoided	Asthma Attacks Avoided	Lost Work Days Avoided
California	$169.0	15,300	440,000	2,160,000
Texas	$104.0	9,320	346,000	1,520,000
Pennsylvania	$86.8	7,940	148,000	735,000
Florida	$85.6	7,760	142,000	766,000
Ohio	$68.5	6,280	137,000	635,000
New York	$68.2	6,200	159,000	825,000
Illinois	$59.5	5,410	138,000	670,000
Michigan	$51.4	4,700	97,400	466,000
New Jersey	$43.6	3,960	92,400	464,000
Indiana	$36.8	3,360	83,000	373,000
North Carolina	$35.3	3,210	79,100	387,000
Virginia	$29.7	2,700	70,900	350,000
Georgia	$29.3	2,640	78,500	385,000
Maryland	$27.8	2,530	63,600	315,000
Tennessee	$24.9	2,180	53,800	255,000
Kentucky	$20.4	1,850	43,000	200,000
Wisconsin	$19.2	1,760	39,300	186,000
Missouri	$18.8	1,710	41,300	193,000
Massachusetts	$18.0	1,640	35,500	195,000
Louisiana	$17.8	1,610	40,800	184,000
South Carolina	$17.0	1,550	32,000	154,000
Arizona	$15.1	1,360	38,500	182,000
Minnesota	$14.9	1,350	36,600	171,000
Alabama	$14.3	1,300	28,300	134,000

State	Cumulative Health Benefits, 2020 - 2050			
	Health Benefits (Billions)	Premature Deaths Avoided	Asthma Attacks Avoided	Lost Work Days Avoided
Connecticut	$13.7	1,250	27,400	143,000
Oklahoma	$12.3	1,120	31,700	136,000
Iowa	$10.8	989	24,500	108,000
West Virginia	$9.8	898	16,100	81,200
Colorado	$9.5	857	31,200	151,000
Arkansas	$9.5	865	20,300	90,700
Mississippi	$8.5	773	18,300	80,600
Nevada	$7.5	676	14,800	78,900
Kansas	$6.9	625	18,100	77,400
Washington	$5.9	531	15,000	73,200
Utah	$5.7	506	26,100	94,300
Nebraska	$5.2	476	14,300	60,500
Delaware	$5.1	462	11,200	55,100
Maine	$4.5	402	5,870	31,000
New Hampshire	$3.9	356	5,860	32,800
Rhode Island	$3.8	348	6,570	35,600
New Mexico	$3.0	273	7,380	32,300
Oregon	$2.7	242	5,600	28,300
Vermont	$2.0	183	2,880	15,700
Idaho	$1.8	166	4,850	20,000
District of Columbia	$1.7	149	5,680	36,400
South Dakota	$1.6	143	4,140	16,500
North Dakota	$1.5	133	3,300	14,800
Montana	$1.3	122	2,550	11,800
Wyoming	$0.9	81	2,290	9,870

Note: Health results include the number of avoided adverse health impacts and the economic value of these health risk reductions at a 3% discount rate and reflect higher range estimates associated with the Di et al. (2017) health study. Mortality estimates are grown from EPA 1990 value of a statistical life using standard income growth data while non-fatal costs are presented in 2017$ values.

Note: Data for Alaska and Hawaii are not presented in this report because the US EPA COBRA Model provides health outputs for the contiguous United States.

Local Results: Public Health Benefits Across America

Communities across the United States stand to benefit from the widespread transition to zero-emission transportation and electricity generation. As transportation emissions are a dominant source of local exposures in many communities, a carefully and equitably designed shift to non-combustion transportation can mean cleaner air for all, and especially those most burdened by pollution from these sources today. Similarly, a shift away from fossil-fueled electricity generation is critical to improving the health of those most impacted by emissions from power plants, including in lower-income, rural communities across the United States.

This analysis found that the 100 U.S. counties (roughly 3 percent of all counties assessed) with the highest percent populations of People of Color could experience approximately 13 percent of the cumulative health benefits of this transition ($155 billion, between 2020-2050). Expanding this further, the 500 U.S. Counties (16 percent of counties assessed) with the highest percent populations of People of Color could experience 40 percent of the benefits, or $487 billion cumulatively between 2020 and 2050. It is also clear that the presence of benefits within these counties does not directly translate to benefits to individual neighborhoods or residents, however. This is an indicator of the urgent need to center equity in policies and investments to ensure access to the benefits of pollution-free mobility and power.

Additional analysis of the benefits in rural communities, lower-income communities, and neighborhood exposure levels could provide deeper insights into more equitable policy and investment designs. At a broader scale, this analysis shows a leveling of benefits across the country as the locations of power plants and transportation hubs are often impacting communities with varying socioeconomic characteristics.

As shown in the table on the next page, communities across the United States could experience billions in public health benefits, and significantly reduce premature deaths, asthma attacks and other negative health consequences of polluted air through 2050. The table includes the 25 Metropolitan Areas across the United States showing the largest cumulative health benefits by 2050 considering the shift to non-combustion electricity generation and zero-emission transportation.

Top 25 Metro Areas, Public Health Benefits	Cumulative Public Health Benefits 2020-2050			
	Health Benefits (Billions)	Premature Deaths Avoided	Asthma Attacks Avoided	Lost Work Days Avoided
1. Los Angeles-Long Beach, CA	$95.5	8,680	241,000	1,210,000
2. New York-Newark, NY-NJ-CT-PA	$84.2	7,660	206,000	1,070,000
3. Chicago-Naperville, IL-IN-WI	$46.5	4,230	113,000	552,000
4. San Jose-San Francisco-Oakland, CA	$42.5	3,850	113,000	561,000
5. Philadelphia-Reading-Camden, PA-NJ-DE-MD	$41.1	3,760	86,600	424,000
6. Washington-Baltimore-Arlington, DC-MD-VA-WV-PA	$38.9	3,540	104,000	516,000
7. Miami-Port St. Lucie-Fort Lauderdale, FL	$36.5	3,320	62,300	342,000
8. Houston-The Woodlands, TX	$33.4	3,000	130,000	568,000
9. Detroit-Warren-Ann Arbor, MI	$29.2	2,690	55,100	268,000
10. Dallas-Fort Worth, TX-OK	$28.0	2,530	88,300	405,000
11. Boston-Worcester-Providence, MA-RI-NH-CT	$22.7	2,070	43,000	238,000
12. Atlanta-Athens-Clarke County-Sandy Springs, GA-AL	$20.9	1,890	59,400	296,000
13. Cincinnati-Wilmington-Maysville, OH-KY-IN	$20.7	1,900	51,600	233,000
14. Cleveland-Akron-Canton, OH	$20.3	1,870	31,500	153,000
15. Pittsburgh-New Castle-Weirton, PA-OH-WV	$19.9	1,830	26,100	138,000
16. Orlando-Lakeland-Deltona, FL	$12.9	1,160	22,400	121,000
17. San Diego-Chula Vista-Carlsbad, CA	$12.4	1,100	29,200	151,000
18. Indianapolis-Carmel-Muncie, IN	$12.2	1,120	32,000	144,000
19. St. Louis-St. Charles-Farmington, MO-IL	$12.2	1,120	25,800	122,000
20. Minneapolis-St. Paul, MN-WI	$11.7	1,070	30,700	145,000
21. Phoenix-Mesa, AZ	$11.0	994	30,700	145,000
22. Tampa-St. Petersburg-Clearwater, FL	$10.9	988	20,100	108,000
23. Charlotte-Concord, NC-SC	$9.2	833	23,200	113,000
24. Harrisburg-York-Lebanon, PA	$8.8	805	16,500	78,700
25. San Antonio-New Braunfels-Pearsall, TX	$8.8	791	25,200	112,000

Note: Health results include the number of avoided adverse health impacts and the economic value of these health risk reductions at a 3% discount rate and reflect higher range estimates associated with the Di et al. (2017) health study. Mortality estimates are grown from EPA 1990 value of a statistical life using standard income growth data while non-fatal costs are presented in 2017 $ values.

Note: The counties assigned to a metropolitan area follow the groupings determined by the White House Office of Management and Budget (OMB) and used by the U.S. Census Bureau. The Metropolitan Statistical Areas and Combined Statistical Areas are used as the basis for considering populations at risk in these urban areas because they reflect the "high degree of social and economic interaction as measured by commuting ties," as OMB describes them. In some cases, metropolitan area results may exceed state results due to geographies of metropolitan areas crossing state lines.

Policy Recommendations to Achieve Public Health and Climate Benefits

At every level of government, transportation and energy decisions are essentially public health decisions. The phase-out of combustion in the transportation and electricity generation sectors is critical as the nation transitions to a healthier future. Continued investments in combustion technologies may prolong the use of harmful fuels or otherwise delay investment in healthier choices today. Public leaders must align transportation and energy decisions and investments with the protection of public health and reductions in harmful emissions.

Recommended Federal Policies to Achieve Public Health Benefits of Zero-Emission Transportation and Electricity Generation

The Federal Government has a critical opportunity to move the nation to healthier, pollution-free transportation and power systems through a combination of strong policies and investments in zero-emission technologies and infrastructure, actions that enjoy broad public support according to a recent American Lung Association poll.[vi] A key down payment was made in the transition to zero-emission transportation with the President signing the Bipartisan Infrastructure Law in November 2021. This law invests $2.5 billion in zero-emission school buses and set $7.5 billion in motion to expand the national infrastructure for zero-emission vehicles — an important start to the larger, and longer-term public/private investments needed. These investments must not only continue and scale up, but must be paired with stronger laws and rules to reduce harmful air and climate pollution:

- Fully implementing the provisions of the bipartisan infrastructure and vehicle investments and continuing to increase funding for non-combustion electricity generation and transportation as the nation continues to invest in a healthier future.
- Extending and increasing incentive and grant programs to support zero-emission vehicle purchases by consumers, transit agencies, school districts and other entities.
- Leading by example by converting public fleets to zero-emission vehicles immediately.
- Congress must pass legislation to accelerate the transition to zero-emission transportation more broadly than contained in the Bipartisan Infrastructure Law and to ensure more equitable distribution of clean air benefits.
- US EPA must act quickly to update National Ambient Air Quality Standards (NAAQS) for NO2, SO2, carbon monoxide, lead, ozone and particle pollution in line with the scientific understanding of what levels are appropriate with an adequate margin of safety of the most vulnerable communities.
- US EPA and the National Highway Traffic Safety Administration (NHTSA) must adopt standards that drive the complete transition to zero-emission passenger vehicles.
    - EPA has finalized regulations that help clean up carbon pollution from the light-duty vehicle sector through Model Year 2026. NHTSA must finalize the Corporate Average Fuel Economy Standards (CAFE) regulations through 2026 for light-duty vehicles.
    - These actions must be followed by increasingly stronger rules beyond 2026 that deliver on President Biden's goal for 50 percent of vehicles sold in the United States to be zero-emission by 2030, and a more complete transition to follow shortly thereafter.

- US EPA must move quickly to approve the next generation standards for heavy-duty trucks in 2022 that acknowledge the growing market for combustion-free medium- and heavy-duty vehicles:
  - More stringent greenhouse gas emission standards for heavy trucks by 2027
  - 90 percent reduction in smog-forming NOx emissions for new trucks by 2027
  - These actions must be followed by stronger rules for subsequent years that drive a complete transition to zero-emission heavy-duty vehicles
- The Biden Administration's Justice40 initiative must ensure that major investments are made in environmental justice communities throughout the United States. These investments must ensure that the benefits of zero-emission technologies are felt in historically underserved and over-polluted communities.
  - Treat 40 percent investment as a minimum requirement
  - Ensure that investments are located in communities of concern, and that health, climate and other benefits actually accrue within these communities
- Increase and sustain policies, incentives and investments to accelerate non-combustion renewable electricity generation and the retirement of combustion-based power plants to achieve the Biden Administration's target for 100 percent carbon pollution-free electricity by 2035.

Broad Public Support for Transportation Electrification

70% of American voters believe the federal government should:

- implement policies that support a transition to zero-emission vehicles; and
- require that by 2040 all new freight trucks, buses and delivery vans sold in the U.S. must produce zero tailpipe emissions.

American Lung Association Poll, 2021

Recommended State Policies to Achieve Public Health Benefits of Zero-Emission Transportation and Electricity Generation

Under the Federal Clean Air Act, California holds the authority to seek a waiver to enact stronger-than-national standards to address its air pollution challenges, while states can — and increasingly do — follow these more health-protective rules. At present, 15 states have adopted zero-emission vehicle standards and increasing numbers are pursuing zero-emission truck requirements. In addition to adopting these standards, states must invest in the fueling infrastructure needed to support the growing market, while also supporting the transition to non-combustion renewable power.

State	Zero Emission Vehicle Standard	Zero Emission Truck Standard	Zero Emission Truck MOU
California	●	●	●
Colorado	●		●
Connecticut	●		●
Hawaii			●
Maine	●		●
Maryland	●		●
Massachusetts	●	●	●
Minnesota	●		
Nevada	●		
New Jersey	●	●	●
New York	●	●	●
North Carolina			●
Oregon	●	●	●
Pennsylvania			●
Rhode Island	●		●
Vermont	●		●
Virginia	●		●
Washington	●	●	●
Washington, DC			●

Note: The California Zero Emission Vehicle standard sets increasing requirements for zero-emission passenger vehicle sales. The California Advanced Clean Truck standard sets similar sales percentages for medium- and heavy-duty truck sales. The Multi-State Memorandum of Understanding creates a coordinated approach to achieving 30 percent zero-emission truck sales by 2030 and 100 percent sales by 2050.

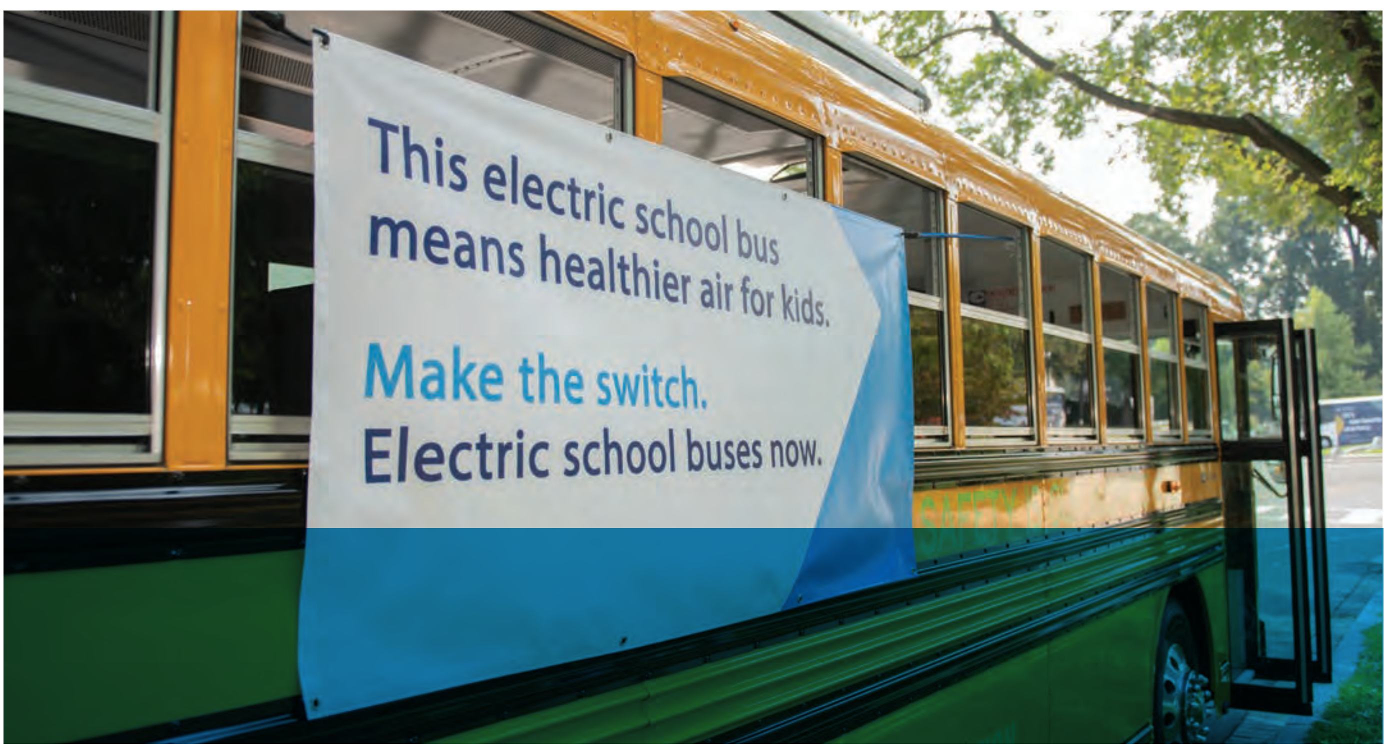
- States must adopt state standards for passenger vehicles and medium- and heavy-duty trucks to require that 100 percent of sales are zero-emissions.
- States must lead by example by converting public fleets to zero-emission vehicles.
- States must establish incentive programs to accelerate zero-emission mobility options and set clear requirements for the equitable distribution of incentive funding and infrastructure investments so that all communities (including urban, rural, lower-income, etc.) have access to the benefits of zero-emission mobility.
- States must remove barriers to equitable utility investments in zero-emission infrastructure serving all communities, and invest in upgrades needed to integrate light-, medium- and heavy-duty zero-emission vehicles across the grid.
- California must utilize its unique Clean Air Act authority to develop and implement stringent near- and long-term zero-emission standards (e.g., Advanced Clean Cars, Advanced Clean Trucks) that support attainment of NAAQS and state climate policies while also ensuring equity is central to policy design.
- States must enact programs and investments in infrastructure, consumer rebates and other supportive programs to join the growing list of jurisdictions following these more health-protective Advanced Clean Cars and Advanced Clean Trucks standards.
- States must not preempt actions by local governments seeking to expand zero-emission fueling infrastructure and clean electricity installations or to set more protective building codes.
- States can also join regional or other partnerships such as the Regional Electric Vehicle Midwest Coalition or the Multi-State Memorandum on Zero Emission Trucks to leverage broader resources to achieve healthier transportation.
- States must adopt and accelerate clean electricity standards, modernize electric grids and ensure equitable access to clean electricity to ensure full benefits of non-combustion electricity generation and transportation.

Recommended Local Policies to Achieve Public Health Benefits of Zero-Emission Transportation and Electricity Generation

In planning and building bike lanes and sidewalks, transit routes and carpool lanes, local government decisions impact how we move, and how safely and easily it is we do so. Local decisions can also ease the transition to zero-emissions. There are examples across the nation of public agencies, rural and urban transit fleets and school districts incorporating or fully converting to zero-emission technologies within their own fleets and make it easier for residents and businesses to make the switch and capture the benefits of cleaner air. Local governments must:

- Develop resources with utilities, manufacturers, local and regional governments and others to accelerate regional deployment of zero-emission vehicles, electricity and associated infrastructure
- Shift public fleets to zero-emissions across all weight classes.
- Establish simplified renewable energy and zero-emission fueling infrastructure installation processes for businesses, homeowners, renters and apartment managers.
- Coordinate with local agencies to implement zero-emission mobility options for lower-income neighborhoods, including car share, bike share, on-demand transit, etc.
- Ensure building code requirements follow best practices for charging readiness.
- Develop non-financial incentives such as preferred parking, sidewalk charging or other, visible measures to support residents in this transition.

At all levels, local, state and federal partners must collaborate and coordinate to deliver the framework for accessible, sustainable and reliable deployment of zero-emission transportation.



Conclusion

Too many Americans face unhealthy air that is being polluted by the transportation and electricity generation sectors. Climate change is making air pollution worse. This is especially true in lower-income communities and communities of color experiencing highly concentrated doses of pollution from diesel hotspots, refineries, power plants and other fossil fuel facilities. To reduce air pollution burdens and disparities, and to protect public health against the worst impacts of climate change, policies and investments must align with rapid reduction and elimination of combustion in these sectors. Doing so could yield over $1.2 trillion in public health benefits across the United States between 2020 and 2050 and $1.7 trillion in climate benefits. Acting now provides opportunities for major benefits in the near term and establishes pathways for generations to breathe healthier air.

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https://www.bakersfield.com/news/inspectors-find-14th-oil-well-leaking-methane-in-bakersfield-residential-area/article_76b33f18-e127-11ec-98ae-cbb404e66185.html

Inspectors find 14th oil well leaking methane in Bakersfield residential area

The Bakersfield Californian
May 31, 2022

in this May 2022 file photo, idle oil wells found to have been leaking methane, marked with blue bins, can be seen from a housing development on Morningstar Avenue. Authorities said they do not know how much methane had been escaping from these wells, which are located as close as an eighth of a mile from the neighborhood.

Eliza Green / The Californian

State regulators have discovered another oil well leaking methane in a residential area in Bakersfield, bringing to 14 the number found fitting that description in the past two weeks.

According to information the state Department of Conservation provided Tuesday, the leak was found in the vicinity of 216 Durham Court, which is northeast of the intersection of California Avenue and Stockdale Highway, at a facility operated by Griffin Resources LLC. The previous batch of leaky wells was located in northeast Bakersfield near the intersection of Morning Drive and Morningstar Avenue.

MORE INFORMATION

Authorities lack methane data from local oil well leaks

Leaky oil well count hits 21

Newsom lays out plans for methane-detecting satellites after 9 more leaky wells come to light

Recommendations to CalGEM for Assessing the Economic Value of Social Benefits from a 2,500' Buffer Zone Between Oil & Gas Extraction Activities and Nearby Communities

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Technical assistance provided by Neil Maizlish (PhD, CA Dept of Public Health (retired)), Kyle Ferrar (Western Program Coordinator, FracTracker Alliance), David J.X. Gonzalez (PhD Candidate, Stanford), Jill Johnston (PhD, USC) and Bhavna Shamasunder (PhD, Occidental College)

December 2020

Introduction

The purpose of this memo is to recommend guidelines to CalGEM for evaluating the economic value of the social benefits and costs to people and the environment in requiring a 2,500 foot setback for oil and gas drilling (OGD) activities. The 2,500' setback distance should be considered a minimum required setback. The extensive technical literature, which we reference below, analyzes health benefits to populations when they live much farther away than 2,500', such as 1km to 5km, but 2,500' is a minimal setback in much of the literature. Economic analyses of the benefits and costs of setbacks should follow the technical literature and consider setbacks beyond 2,500' also.

The social benefits and costs derive primarily from reducing the negative impacts of OGD pollution of soil, water, and air on the well-being of nearby communities. The impacts include a long list of health conditions that are known to result from hazardous exposures in the vulnerable populations living nearby. The benefits and costs to the OGD industry of implementing a setback are more limited under the assumption that the proposed setback will not impact total production of oil and gas.

The comment letter submitted by Voices in Solidarity against Oil in Neighborhoods (VISIÓN) on November 30, 2020 lays out an inclusive approach to assessing the health and safety consequences to the communities living near oil and gas extraction activities. This memo addresses how CalGEM might analyze the economic value of the net social benefits from reducing the pollution suffered by nearby communities. In doing so, this memo provides detailed recommendations on one part of the broader holistic evaluation that CalGEM must use in deciding the setback rule.

This memo consists of two parts. The first part documents factors that CalGEM should take into account when evaluating the economic benefits and costs of the forthcoming proposed rule. These include factors like the adverse health impacts of pollution from OGD, the hazards causing them and their sources, and the way they manifest into social and economic costs. It also describes populations that are particularly vulnerable to pollution and its effects as well as geographic factors that impact outcomes.

The second part of this memo documents the direct and indirect economic benefits of the proposed rule. Here, the memo discusses the methods and data that should be leveraged to analyze economic benefits of reducing exposure to OGD pollution through setbacks. This includes the health benefits, impacts on worker productivity, opportunity costs of OGD activity within the proposed setback, and the fact that impacted communities are paying the external costs of OGD.

Summary of Factors that CalGEM Should Consider

Adverse Health Impacts

A recent review by Johnston *et al* (2018) identified *only* the following health impacts from exposure to oil extraction: cancer, liver damage, immunodeficiency, and neurological symptoms[1]. However, the adverse health impacts from the soil, air and water pollution were not included because of limited knowledge about exposure. Below we include a more comprehensive list of the health outcomes that are likely associated with this air, soil and air pollution. These range from premature mortality, acute hospitalizations, and increased emergency room and ambulatory care visits; poor birth outcomes, to absenteeism and low productivity at work and school to increased need for chronic care and reduction in life expectancy[2] [3].

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A single drill site typically operates for decades, and the extraction produces emissions of multiple health-hazardous air pollutants, including benzene, toluene, ethylbenzene, xylene, formaldehyde, hydrogen sulfide, and methylene chloride. Many of these compounds are known to be toxic to human health, carcinogenic, cause respiratory harm, or are endocrine disrupting chemicals and can cause long-term developmental or reproductive harm—a consideration for health across generations[4] [5] [6] [7]. These chemicals can migrate off-site due to fugitive emissions, spills, leaks, or accidents.

Scientific studies on upstream oil and gas extraction from many parts of the US and globally provide a substantive base of evidence documenting health impacts. In California, two recent studies demonstrate significant increases in adverse birth outcomes for pregnant women living within 1 km and 10 km of wells[8] [9]. Despite different extraction procedures, geology and varying local demographics, scientific studies have consistently demonstrated significant associations with adverse birth outcomes in

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Pennsylvania[10 11 12], Colorado[13 14], Texas[15], and Oklahoma[16]. Adverse perinatal effects are associated with maternal proximity of ½ mile to 3 miles from drill activity.

Residents near petroleum extraction sites report symptoms of throat and nasal irritation, eye burning, sinus problems, headaches, skin problems, severe fatigue, loss of smell, cough, nosebleeds, and psychological stress[17 18 19 20 21]. Among adults, risk factors for cardiovascular disease rise with the intensity of nearby oil and gas drilling [22]. These

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symptoms increased in incidence among individuals living near oil and gas facilities compared to those living farther away. Neurological symptoms, kidney damage and thyroid problems also increase among those living in oil extraction regions compared to those living farther away, while stress, including social and economic stress, can make these health conditions worse[23].

Cancer mortality is higher in communities exposed to oil extraction [24] [25] [26] [27]. For example, in Colorado, children with leukemia were 4.6 times more likely to live in an area with dense petroleum extraction[28].

Toxic emissions leak into the air surrounding oil and gas production especially during the production phase. With the lengthy operation timeframes, episodic peak emission events, and the largest number of hazardous air pollutants from the various equipment and operations, this period has the potential to emit the highest concentrations of hazardous air pollutant over the longest period of time[29]. The truck traffic to and from the drilling site and the operation of diesel equipment releases toxic air pollutants compromising air quality[30] [31]. Exposure to these air pollutants have been shown to be

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higher near drilling sites[32] [33] [34] [35] including in Los Angeles[36] [37]. Adverse human health impacts result from exposure to these chemicals[38]. Acute inhalation of petroleum hydrocarbons increases the incidence of eye irritation and migraine headaches[39] [40] [41] as well as asthma symptoms[42] [43] [44]. The high decibels of noise around drilling operations is an important co-exposure[45] [46] [47].

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Animals living in oil producing regions accumulate toxins in various organs, especially toxic metals, that lead to kidney damage [48] [49]. Elevated levels of toxic metals and petroleum hydrocarbons have been measured in soil and water near oil extraction sites[50] in Texas[51], China[52] [53] [54], Nigeria[55], and Iraq[56].

Hydrogen sulfide is an odoriferous gas associated with oil drilling. Most human organ systems are susceptible to the toxic effects of H2S, especially the central nervous system, the respiratory system, the cardiovascular system, the gastrointestinal system, and mucus membranes[57]. At ambient levels, odorant chemicals may irritate the eyes, nose and throat and induce symptoms such as nausea, vomiting, headaches, stress, negative mood, and stinging sensations[58] [59]. Odors that are perceived as unpleasant, embarrassing, or sickening may interfere with mood, beneficial land use, and social activities. Chronic exposure to elevated ambient concentrations contribute to harm to

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the respiratory system in adults and children and increase cough, headaches and wheezing[60 61].

Buffers or setbacks help to limit exposures to harmful contaminants that adversely impact human health[62 63 64 65]. From the public health perspective, given the overwhelming weight of evidence of adverse health effects from oil and gas development, it is essential to reduce exposures to these harmful pollutants in communities especially in homes, schools, and workplaces.

Hazards Contributing to Adverse Health Impacts

CalGEM's assessment of the proposed rule's health impacts should capture the effects of the following air pollutants: PM2.5, PM10, NOX, SO2, ozone, volatile organic compounds (VOCs, a broad category including benzenes, toluenes, hydrogen sulfide, poly aromatic hydrocarbons, and related chemicals), and other compounds used in fracking for which not much is known about toxicity. The emissions can come from engines, outgassing, flares, leaks, or proppants. Pollution of the soil and water are also essential to consider, as are psychological stressors such as light and noise.

Vulnerable Populations

Some population groups are especially vulnerable to these hazards and have increased risk of harm from exposure. These groups include young children and the elderly, pregnant women, poor and disadvantaged communities that often suffer food insecurity and inadequate health care, Black and Latinx community members, and those with pre-existing health conditions such as diabetes, lung disease, heart disease, and asthma. To ensure limited exposure, OGD should have at least a 2,500' setback from places where these vulnerable populations congregate such as schools, day care, senior and health care facilities, and residences.

[60] Jaakkola, J. J., Paunio, M., Virtanen, M., & Heinonen, O. P. (1991). Low-level air pollution and upper respiratory infections in children. American Journal of Public Health, 81(8), 1060-1063. doi:10.2105/AJPH.81.8.1060

[61] Marttila, O., Jaakkola, J. J. K., Vilkka, V., Jappinen, P., & Haahtela, T. (1994). The South Karelia Air Pollution Study: The Effects of Malodorous Sulfur Compounds from Pulp Mills on Respiratory and Other Symptoms in Children. Environmental Research, 66(2), 152-159. doi:10.1006/enrs.1994.1051

[62] Fry, M. (2013). Urban gas drilling and distance ordinances in the Texas Barnett Shale. Energy Policy, 62, 79-89.

[63] Haley, M., McCawley, M., Epstein, A. C., Arrington, B., & Bjerke, E. F. (2016). Adequacy of current state setbacks for directional high-volume hydraulic fracturing in the Marcellus, Barnett, and Niobrara Shale Plays. Environmental Health Perspectives, 124(9), 1323-1333.

[64] McKenzie, L. M., Allshouse, W. B., Burke, T., Blair, B. D., & Adgate, J. L. (2016) *opcit*

[65] Banan, Z., & Gernand, J. M. (2018). Evaluation of gas well setback policy in the Marcellus Shale region of Pennsylvania in relation to emissions of fine particulate matter. Journal of the Air & Waste Management Association, 68(9), 988-1000.

Sources of Exposure to Hazards

People living and working nearby OGD can be exposed to the above-mentioned hazards through air, water, and the environment, and the workers involved with OGD have occupational exposure.

- Toxic air pollution results from aerosolizing of the polyaromatic hydocarbons, fine and ultrafine particulate matter, and other chemicals from the wells themselves and from the engines in the vehicles and in the wells. The first few months of preparing a new well result in especially high levels of toxins and pollutants in the air from the traffic and engines required for initiating production. Then, over the relatively long periods of production, chemicals leak consistently in high cumulative volume. Even after production has ended, improperly plugged wells may continue to leak toxic chemicals into the air, soil, and water for many years.
- The chemicals used in OGD (some of which are unknown since they are protected by trade secrets) contaminate water through several avenues: contamination of aquifers above or below the wells, spills and leakage of excess water contaminated with petrochemicals into the soil around the wells, leakage from unlined excess water storage pools, use of excess water from wells for irrigation, among others.
- Environmental exposures that harm health include direct exposure to soil contaminated from leaks and spills, as well as indirect exposure to food grown on contaminated soil and/or irrigated with contaminated water. Excess light and noise from activity around wells increase anxiety.
- Humans are also exposed to hazards through the negative impacts of OGD on plants and wildlife, which include habitat loss and fragmentation.

Geographic Factors

It is important to consider the role of geography in determining the impacts of OGD. These factors include:

- The number and demographics of the population living, working, and engaging in activities within 2,500’ of oil and gas operations has a direct bearing on the negative effects of OGD. Special attention must be paid to vulnerable populations.
- The presence and proximity of aquifers, reservoirs or other bodies of water or watersheds affect the likelihood and severity of negative health impacts through water pollution.
- The density of wells in the area must be considered to determine the degree of negative impacts. It is insufficient to merely note the presence or absence of any wells.

- The proximity of wells in the area must be considered to determine the degree of negative impacts. It is insufficient to merely note whether wells fall within the proposed 2,500’ setback.
- The well geology, production method, and history of the production company must be considered to estimate the risk of spill, leak, and inappropriate disposal or reuse of produced water containing chemicals.
- Where and how the exposures take place must be considered : air – inhaled, water – contamination of wells (rural) and aquifers (rural vs urban watershed), spills of oil and gas and/or the chemicals used for oil and gas development
- The level of toxic exposure in air (e.g., local AQI), water (presence of toxins), and environment must be considered to determine the marginal harm from additional exposures.

Economic Benefits of Proposed 2,500’ Setback Rule

Economic Value of Social and Health Benefits of a Proposed Setback Rule

As the above sections document, the adverse health impacts range from increased acute diseases (such as asthma and increased incidence and severity of COVID19) to chronic conditions such as cancer, reduced cardiopulmonary function, and the long-term consequences of poor birth outcomes on life expectancy. All of these impacts result in high social and economic costs to the impacted population (i.e., people living within 2,500’ of OGD). Social and economic costs of health deterioration resulting from exposure to toxic emissions for extraction activities include costs related to morbidity, such as increased health services, productivity losses from disease and absenteeism, long term care for low birth weight or preterm birth, and mortality, with the value of a statistical life estimated by the US Dept of Transportation in 2016 as $9.6 Million per death.[66]

Here we provide guidelines based on accepted practices for estimating the economic value of the health benefits of a policy rule.[67] Our proposed method for estimating the economic value of the health benefits from reduced ambient air pollution on the nearby communities is conservative because it includes the economic valuation of only a few of the known toxic air pollutants released by oil and gas extraction activities. Often the

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[66] See US Department of Transportation, “Revised Departmental Guidance on Valuation of a Statistical Life in Economic Analysis.”

[67] See the United States Environmental Protection Agency’s *Guidelines for Preparing Economic Analyses.* https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses

local air pollution analysis involves only PM2.5, and also ozone in some studies. As the above literature review shows, these are only two air pollutants out of the many air, water, and environmental hazards of OGD known to cause negative health impacts. Therefore, the estimated total social benefit of the proposed rule that results from an analysis of only a few ambient air pollutants must be viewed as only a very small part of the actual total social benefits for the impacted population.

The economic valuation of the proposed 2,500' setback's effects on improved health for the impacted population through improving air quality (e.g., reducing PM2.5 and ozone) requires a rigorous analysis done by researchers who are familiar with undertaking statistical analysis of the publicly available data. Then, this economic analysis can be added to the CalGEM health impact analysis to systematically consider the full range of potential impacts of the proposal on health determinants, health status, and health equity.[68]

CalGEM should integrate the quantitative economic and health analyses into the qualitative data from stakeholders affected by the proposal, particularly impacted vulnerable populations who provided testimony in pre-rulemaking hearings and with materials directly submitted to CalGEM. This use of qualitative data is in line with the official standard for health impact analysis: "The lack of formal, scientific, quantitative, or published evidence should not preclude reasoned evaluation of health impacts. The expertise and experience of affected members of the public (local knowledge), whether obtained via the use of participatory methods, collected via formal qualitative research methods, or reflected in public testimony, comprise a legitimate source of evidence."[69]

The first step in evaluating the economic benefits of improved health due to improving air quality is to determine the improvement in air quality. To provide concrete recommendations on how CalGEM can do this, we discuss an ongoing research project being conducted at by David Gonzalez and colleagues at Stanford University[70] that uses panel data from California air pollution monitors to estimate the ambient air pollution emitted from nearby oil and gas wells. We think that this research can be useful to CalGEM because it uses California data, it estimates the increase in pollution from one additional well by using panel data over 21 years, and it uses a rigorous statistical method.

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[68] Ibid

[69] *Health Impact Analysis* https://hiasociety.org/resources/Documents/HIA-Practice-Standards-September-2014.pdf See the list of practice standards to be followed.

[70] Gonzalez, David J.X. Research Project on Extractive Industries and Health Equity in the Emmett Interdisciplinary Program in Environment and Resources at Stanford University.

The Gonzalez *et al.* study examines the effects of upstream oil and gas preproduction (drilling sites) and production activities (total volume of oil and gas) on the concentrations of ambient air pollutants in California. The data comes from 360 monitors in the EPA Air Quality System over the time period 1999-2019, which provided approximately 1.6 million daily observations including daily concentrations of ambient air pollutants previously reported to be associated with oil and gas production (PM2.5, NO2, O3, SO2, VOCs). The research team obtained data on the preproduction sites and production by well from CalGEM. For each monitor-day, they assessed exposure to upwind drilling sites and total production volume of oil and gas within 1 km bins out to 1 km from the monitor. They estimate adjusted fixed effects linear regression models for each pollutant, controlling for geographic, seasonal, temporal, and meteorological factors.[71] They find that it is important to control for season, year, precipitation, wind speed, and presence of wildfire smoke plumes. Their preliminary findings show higher concentrations of PM2.5 with exposure to upwind drilling sites within 3 km, higher concentrations of O3 for drilling sites at 2-4 km, and higher concentrations of SO2 for drilling sites within 1 km.

A preliminary estimate of the social benefits that would accrue as a result of a decline in premature mortality from mandated setbacks of 2,500' would be calculated as follows using a conservative estimate based solely upon the excess PM2.5 generated by OGD within 2 km radius of wells. The excess $PM_{2.5}$ is approximately 1.8 μg/m^3 for an additional drilling site within a 2 km (6,561') radius, an estimate that can be reasonably applied to 2,500'.[72] Recent studies demonstrate that 10 microgram/M3 higher levels of PM2.5 are associated with a 7.3% increase in all cause mortality rate.[73] This increase in all-cause mortality rate doubles among those with low socioeconomic status and almost triples among Blacks. Those living near oil and gas wells are frequently of low socioeconomic status and many are Black, as discussed below.

If oil and gas wells are moved to at least 2,500' km away from where people live, go to school, work, and play, and inhabitants' exposure to $PM_{2.5}$ declines by only 1 μg/m^3, a conservative estimate based on the estimated effect of 1.8 μg/m^3, then mortality rates would decline by at least 0.73%. The overall mortality rate in 2018 in California was 609 per 100,000. For each 100,000 people living within 1 km of a well, 609 deaths

[71] The findings were tested for robustness by using alternative model specifications and by conducting placebo tests using exposure to wells that were downwind and in random wind directions from the monitors.

[72] Gonzalez, David J.X., Christina K. Francis, Michael Baiocchi, Mark Cullen, and Marshall Burke. Upstream oil and gas production and ambient air quality in California. Research Project in the Emmett Interdisciplinary Program in Environment and Resources at Stanford University, Work in progress (2020)

[73] Qian Di MS, Wang Y, Zanobetti A, Wang Y, Kourtrakis P, Choirate C, Dominici F, Schwartz J. 2017. Air Pollution and Mortality in the Medicare Population. N Engl J Med 2017 June 29;376(260:2513-2522). Berger RE, Ramaswami R, Solomon CG, Drazen JM. 2017. Air Pollution Still Kills. N Engl J Med 2017:376:2591-2592.

would occur in a year. If wells were moved so that the PM2.5 was 1 $\mu g/m^3$ less for these 100,000 people, then 4.5 premature deaths (0.73%) would be averted annually. With a Value of a Statistical Life of $10,000,000 estimated by the EPA in 2019, then averting 4.5 deaths leads to a social benefit of $**45M annually**. In 2018 **over 850,000 Californians live within 2,500' of an active oil well**,[74] and improving their mortality by decreasing their PM2.5 air pollution would provide social benefits at least **$382.5 million annually**. The social benefit may be greater for communities exposed to intensive oil production activities, where concentrations of PM2.5 would likely be higher. This size of the impacted population is increasing as new wells are drilled. In 2020, 2.17 million Californians live within 2,500' of operational wells (new, active, and idle wells).[75]

However OGD spews much more toxicity in air, soil, and water that cause poor health than just the increase in PM2.5 around wells. The health problems caused by OGD are listed above so that the social benefits from increasing setbacks from wells are much greater than the already high social benefits from decreasing PM2.5 emissions in nearby communities.

Next we look at the demographics of the population living near extraction activities. Public Data from FracTracker[4] provides GIS analysis overlaying oil and gas wells (idle, operational, new; within 2,500' and within 2,500'-5,280') by census block to American Community Survey (2013-2018) block group demographics data (age, non-white, Latinx, poverty rate, distribution of income) with CalEnviroScreen 3.0 by census tract.[76] Here CalEnviroScreen 3.0 is linked to the American Community Survey demographic data.

An aggregation of these data are provided for CalEnviroScreen 3.0 percentile groups (Table 1), and American Community Survey (2013-2018) census block group demographics data (Table 2).

Table 1 maps the distribution of wells in the census block groups with CalEnviroScreen 3.0 data on incidence of asthma (from lowest 0-20% percentile to highest 80-100% percentile groups), incidence of low birth weight, drinking water quality, PM2.5, and Ozone.[77] The relationship between location of wells and specific health problems is complex and must be carefully explained.

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[74] http://priceofoil.org/2018/05/22/skys-limit-california-oil-production-paris-climate-goals/ See also https://www.fractracker.org/2019/07/impact-of-a-2500-oil-and-gas-well-setback-in-california/
[75] https://www.fractracker.org/2020/12/people-and-production/ p 1.
[76] CalEnviroScreen 3.0 rankings were updated June 2018. https://oehha.ca.gov/calenviroscreen
[77] Database created and made available by Kyle Ferrar, Western Program Coordinator, FracTracker Alliance

The large number of wells located in the 60-80th percentile rather than the worst (80-100th percentile) is a result of spatial bias,[78] and the many factors that are aggregated to generate the CES Total Scores. These factors include relative affluence and other indicators of socio-economic status. The majority of the worst (80th-100 percentile for Total CES Score) census block groups are located in low-income urban census block groups, many in Northern California cities that do not host urban drilling operations.

For the asthma rankings, the majority of wells are located in the best CES 3.0 percentile (0-20th percentile) for Asthma. While there is much urban drilling in Los Angeles, the spatial bias in this type of analysis gives more weight to the majority of oil and gas wells that are located in rural areas, which historically have much lower asthma rates. This is a result of the very high incidence of asthma in cities without urban drilling such as the Bay Area and Sacramento (80-100th percentile).

	Operational Well Counts				
	0-20%ile	20-40%ile	40-60%ile	60-80%ile	80-100%ile
Asthma	40,247	19,827	18,902	4,867	19,792
Low Birth Weight	10,186	13,368	14,995	3,236	58,036
Drinking Water	1,019	1,675	53,452	6,214	41,206
PM2.5	5,708	4,237	16,614	70,859	69,987
Ozone	2,238	5,435	6,107	9,898	79,957
Total CES 3.0	1,583	5,756	15,671	65,356	12,985

Table 1. Oil and Gas Wells in CES 3.0 Percentile Groups (2018)

	Distance from an operational oil and gas well		
Demographics	Within 2,500'	2,500' - 1 Mile	Beyond 1 Mile (Statewide)
Non-white	44.44%	43.56%	39.16%
Latinx	43.25%	44.97%	37.79%
Age 0-5	6.08%	6.12%	6.37%
Age <18	21.54%	22.12%	23.39%
Age 65+	13.17%	13.11%	13.68%
Poverty: Under .5 Income to Poverty Ratio	6.51%	6.40%	6.21%
Poverty: .5-.99 Income to Poverty Ratio	8.50%	8.58%	7.92%
Median Annual Household Income < $40k	30.09%	30.73%	28.72%
Median Annual Household Income <$75k	53.53%	54.36%	51.76%

Table 2. California Demographics at Specific Distances from Oil and Gas Wells (U.S. Census Bureau, ACS 2013-2018 5-year Summaries)

[78] This spatial bias results from edge effects of census block groups, where communities living near oil and gas extraction operations may not live in the same census block groups as the oil and gas wells, and are therefore not counted.

Further descriptive analysis of this database can demonstrate the observed demographics by age, race and income of the vulnerable population, and the observed health outcomes for asthma and birthweight. As Table 2 shows, populations living within 2,500’ of operational wells tend to be more non-white and Latinx, under age 5 years, and living in poverty than populations beyond 1-mile.

To simplify the data collection and analysis, the three counties (LA, Orange, and Kern), which have 95% of the population living within 2,500’ of extraction operations, can be used with the assumption that the findings can be generalized to the rest of the state. The percentage of the population in these three counties living within 2,500’ range from 8.5% in Kern to 5.5% in LA.

One recent study on preterm births used an inverse distance-squared weighted index for new and active wells within 10 km of the maternal residence as the predictor variable.[79] Another recent study used exposure to wells as the inactive well count (no inactive wells, 1 well, 2-5 wells, 6+ wells) and production volume from active wells in barrels of oil (no BOE, 1-100 BOE/day, >100 BOE/day).[80]

CalGEM can integrate the economic valuation with evidence of other social benefits related to less polluted water and soil, to reduce noise and light, to alternative uses of the land, along with qualitative data from impacted communities. The broad impact analysis provides the basis for knowing how the proposed 2,500’ setback rule would affect people’s daily lives and their health both today and in the future.

Impact of Air Pollution on Productivity

In its assessment of the benefits of the proposed 2,500’ setback, CalGEM should consider the negative impact of air pollution on worker productivity. Recent studies have found that exposure to PM2.5 and ozone air pollution results in economically significant harm to the productivity of indoor and outdoor workers across a variety of job types. Zivin and Neidell (2012) study the effect of ozone pollution on the productivity of outdoor agricultural workers in California. They find that “ozone levels well below federal air quality standards have a significant impact on productivity: a 10 parts per billion (ppb) decrease in ozone concentrations increases worker productivity by 5.5 percent.” The authors note that “it seems plausible that efforts to reduce pollution could in fact also be viewed as an investment in human capital, and thus a tool for promoting, rather than

[79] Gonzalez DJX, Sherris AR, Yang W, Stevenson DK, Padula AM, Baiocchi M, et al. Oil and gas production and spontaneous preterm birth in the San Joaquin Valley, CA: A case- control study. Environ Epidemiol. 2020;4(4):e099. Epub 2020/08/25.

[80] Tran KV, Casey JA, Cushing LJ, Morello-Frosch R. Residential Proximity to Oil and Gas Development and Birth Outcomes in California: A Retrospective Cohort Study of 2006- 2015 Births. Environ Health Perspect. 2020;128(6):67001. Epub 2020/06/04.

retarding, economic growth.” Chang *et al* (2016) study the effect of outdoor PM2.5 pollution levels on indoor agricultural workers at a pear packing facility in California and find “an increase in PM2.5 pollution of 10 micrograms per cubic meter (μg/m3) reduces the productivity of workers by … approximately 6 percent of average hourly earnings.” This work is consistent with other studies on pollution and productivity for physically demanding occupations, including Chang et al. (2014); Hanna and Oliva (2015); Archsmith, Heyes, and Saberian (2018); He, Liu, and Salvo (2016); Adhvaryu, Kala, and Nyshadham (2016); and Fu, Viard, and Zhang (2017).

To study air pollution’s effect on the productivity of higher-skilled indoor workers, Chang *et al* (2019) examine outdoor PM10 pollution levels (which includes PM2.5) and service sector workers at an indoor call center in China, finding a statistically significant reduction in the number of calls handled per shift. Air pollution’s adverse cognitive effects have even been measured on stock market returns. Heyes *et al* (2016) study S&P 500 returns, finding that “a one standard deviation increase in daily ambient PM2.5 concentrations causes a statistically significant 11.9% reduction in daily percentage returns.”

CalGEM should also consider pollution’s negative impacts on productivity defined more broadly to include non-market productivity like unpaid household work and education outcomes. For education outcomes, there is evidence that early-life exposure to air pollution is associated with negative impacts on neurodevelopment and behavior in infants and young children, autism diagnosis, and attention-deficit/hyperactivity disorder.[81] As noted by Stingone *et al* (2017), there is “evidence that air pollutants contribute to deficits in neurodevelopment that persist into later childhood… affecting cognitive outcomes such as academic achievement.”

When considering any alleged costs to the OGD industry, CalGEM must also consider the potential for such costs to be offset by worker productivity gains across industries due to a reduction in OGD pollution as well as productivity gains defined more broadly to include unpaid household work and education outcomes.

Employment Costs of the Proposed Setback

Few jobs are required in the field once wells are actively operating, with only occasional maintenance or repair work by blue-collar workers. Employment of blue-collar workers is mostly for drilling new wells or reworking wells as they become less productive or have been idle. Professional and managerial employees work at desks in company headquarters. However all oil and gas workers face a cyclical industry that varies with

[81] See Stingone et al (2017) and references therein.

the price of oil and gas. The latest severe downturn occurred with the over-supply of oil just as the pandemic was causing demand to fall.[82]

A recent analysis of employment characteristics in a report by researchers at the University of California Santa Barbara (UCSB report, Section 3)[83] commissioned by CalEPA uses average total compensation for all workers, which is not the correct data for evaluating the pay for blue-collar workers in the extraction sector. Average wages and annual earnings by employment in the blue-collar occupations for the oil and gas extraction industry in California by year is publicly available from the US BLS. Data for 2019 is shown in Table 3.

Table 3: Number of Employees and Median Wages for Blue-Collar Occupations in Oil Extraction Operations[84]

	Employees	Median Wage	Avg. Earnings
Rotary drill operators	1,680 (.27)	$30.58	$68,930
Service unit operators	2,340 (.37)	$26.67	$57,260
Roustabouts	1,350 (.22)	$15.75	$38,730
Derrick operators	890 (.14)	$25.02	$52,310
Total	6,260 (1.00)	--	$55,642

Note that the average annual earnings for these occupations in O&G extraction of $55,642 are much lower than the annual total compensation shown in the UCSB report, which was $161,443 in LA County; $122,344 in Contra Costa County, and $97,765 in Orange county ($2020; avg total compensation over 2016 to 2018), Table 2, p. 74.) You can see that using the UCSB estimated compensation, which is for all occupations and education, is much higher than average earnings for blue collar workers, and is even much higher than the $98,693 for HS or less for the relevant FF workforce (Table on p 79).

Once CalGEM knows the number and occupation of blue-collar jobs per active well, then it must know to what extent phasing out extraction activities in the set-back area reduces jobs and to what extent this is offset by increasing output in the non-impacted area.Then it can calculate the cost of job loss using the OES average earnings data.

[82] See https://www.latimes.com/business/la-fi-bakersfield-oil-20160207-story.html

[83] See “Carbon Neutrality Studies: Reducing Transportation Fossil Fuel Demand and Emissions, and Managing the Decline in Transportation Fossil Fuel Supply” updated 10/21/2020. https://calepa.ca.gov/climate/carbon-neutrality-studies/

[84] Source: California OES Data May 2019, https://www.bls.gov/oes/current/oes_ca.htm#47-0000

Opportunity Costs of Oil and Gas Drilling within the Proposed 2,500' Setback

Any alleged social costs of a reduction in OGD activity within the proposed 2,500' setback are offset by the opportunity costs of that activity. Critically, because investment decisions are made based on private benefits, the social benefits of their opportunity costs may exceed the social benefits of the investments themselves. These opportunity costs include but are not limited to: alternative land uses for OGD wells and access roads within the proposed setback; alternative investments for the capital that would otherwise be used to fund OGD projects within the proposed setback; and the public spending or tax savings that are foregone as a result of the wasteful federal and California tax subsidies enjoyed by the OGD industry for projects within the proposed setback.

To assess the opportunity cost of land used by OGD within the proposed setback, CalGEM should first evaluate the total land area of OGD wells and access roads that would be impacted by the proposed setback. For example, in its 2015 environmental impact report for oil and gas permitting, Kern County calculated the average acreage of land disturbance per producible well for the top 10 oil fields in each of the Western, Central, and Eastern Subareas, accounting for an estimated 97-99% of total production.[85] The report estimates final disturbance factors of 2, 3, and 1.2 acres per producible well for the Western, Central, and Eastern Subareas, respectively.[86] Multiplied by the 52,592 producible wells, these estimates imply approximately 92,000 acres of land disturbed by oil and gas in Kern County. Using similar estimates for Orange and Los Angeles Counties as well as estimates of the number of impacted wells in each county, CalGEM can estimate the opportunity cost of land used by OGD within the proposed setback in terms of acres. Then, a first-order estimate of the associated economic value would be the non-OGD market value of that land.

In addition to the total land use and its value, CalGEM may consider the opportunity cost of land used by OGD within the proposed setback in terms of specific use cases with high social priority. For example, parks and green spaces are well known to impart social and economic benefits through increased property values, health outcomes, living space, recreation, and tourism.[87] In a study of parks in Roanoke, Virginia, Poudyal *et al*

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85 See *Draft Environmental Impact Report for Revisions to the Kern County Zoning Ordinance – 2015. Appendix F.* Kern County Planning and Community Development Department. Bakersfield, CA. July 2015.
Focused on Oil and Gas Local Permitting https://kernplanning.com/environmental-doc/environmental-impact-report-revisions-kern-county-zoning-ordinance-2015-c-focused-oil-gas-local-permitting/
86 Ibid Table 11.
87 See Sherer, Paul M. "The Benefits of Parks: Why American Needs More City Parks and Open Space." *The Trust for Public Land*, 2006.

(2008) find that increasing the size of parks by 20% from their current levels resulted in a consumer surplus increase of $160 per household. Parks are particularly valuable in park-poor places like the city of Los Angeles. “Only 30 percent of its residents live within a quarter mile of a park, compared with between 80 percent and 90 percent in Boston and New York, respectively. If these residents are Latinx, Black, or Asian Pacific, they have even less access to green space.”[88] This contrasts sharply with the fact that in 2019, Los Angeles County was home to 2,478 active wells within 2,500’ of a residence.[89]

The land footprint of OGD also has a high opportunity cost in terms of wildlife habitat and ecosystem services. Allred *et al* (2015) document and measure these costs for wells built in North America from 2000 to 2012, covering “~3 million ha, the equivalent land area of three Yellowstone National Parks.” The costs include the amount of carbon fixed by plants and accumulated as biomass (net primary production, NPP). The authors calculate the NPP loss over this time frame as ~4.5 Tg of carbon. Lost rangelands total “more than half of the annual available grazing on public lands managed by the U.S. Bureau of Land Management. The amount of biomass lost in croplands is the equivalent of 120.2 million bushels of wheat, ~6% of the wheat produced in 2013 within the region and 13% of the wheat exported by the United States.” Moreover, OGD land use harms additional ecosystem functions like wildlife habitat and landscape connectivity, which results in “increasing fragmentation that can sever migratory pathways, alter wildlife behavior and mortality, and increase susceptibility to ecologically disruptive invasive species.”

Other high priority alternative uses of OGD land include the expansion of the housing supply and space for non-OGD local businesses. Expanding the housing supply is a particularly valuable use of land in dense urban environments like Los Angeles County.

To account for another important opportunity cost, CalGEM must consider that the capital that would otherwise be used to fund OGD projects within the proposed setback will be redeployed to other projects. The economic value of those alternative projects, which in some cases may still be OGD projects, should weigh against any costs of the proposed rule alleged by the OGD industry. Importantly, as the investment decision is private and does not capture all social costs and benefits, alternative investments may offer greater net social benefit all by themselves, e.g., through greater employment benefits and more tax revenue, even before consideration of the negative health and environmental effects of OGD.

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[88] See Sherer p. 9

[89] See “Urban Oil and Gas Production in Los Angeles County.” https://arcg.is/1jm1Xj

Finally, OGD projects in California enjoy substantial tax subsidies at the expense of federal and California state taxpayers. It is wasteful and unfair to provide public subsidies to an industry with both outsized private benefits and external costs. Before subsidies, the private benefits already result in greater than the socially optimal level of oil and gas production, a point underscored by the near-universal agreement among economists on the need for a carbon tax to slow climate change.[90] Providing exceptional tax subsidies beyond what other industries enjoy, like percentage depletion and expensing of exploration, makes OGD investment decisions even more inefficient. The proposed setback rule will not significantly impact these massive distortions, which the CALPIRG Charitable Trust estimated as $129 million in California in 1997.[91] However, it may result in lower foregone public spending or greater tax savings associated with the phasing out of OGD projects within the proposed setback, opportunity costs, which, again, must be weighed against any alleged costs of the proposed rule to the OGD industry.

External Costs from Oil and Gas Drilling Should not Be Paid by the Impacted Communities

From a societal viewpoint, we note that the costs of the pollution to the air, water and land impacts the nearby communities, who are paying with their health and well-being for the oil and gas to be extracted from wells within 2,500'. The companies and the state of California are not paying for these social costs.

The state of California needs to recognize that the impacted communities are paying an enormous amount with their health and well-being so oil and gas companies can extract oil and gas for profit. The impacted communities are directly subsidizing the oil and gas companies, and thereby the end users of the oil and gas extracted. The state should not continue to make the impacted communities subsidize oil and gas produced in California.

More broadly, however, the population of the state and the world is also paying for extraction and burning of oil and gas globally. If future California policies reduce production of oil and gas for burning, then the social benefits extend far beyond the nearby impacted communities, and the Social Cost of Carbon can be used to estimate these benefits.

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[90] See "This is not controversial: Bipartisan group of economists calls for carbon tax" by Heather Long. *The Washington Post*. January 16, 2019. https://www.washingtonpost.com/business/2019/01/17/this-is-not-controversial-bipartisan-group-economists-calls-carbon-tax/

[91] See "Crude Policy: Subsidy to the Oil and Gas Industry by California Taxpayers." *CALPIRG Charitable Trust*. December 1997. http://cdn.publicinterestnetwork.org/assets/qM_id3naUNoDMeVTArJdow/Crude_Policy.pdf

Conclusion

As this memo demonstrates, a large literature documents how the health of the people living near oil and gas extraction operations is adversely impacted by the large array of toxins that are emitted into the air, water, and soil. Our focus is on how Californians living near oil and gas wells suffer health problems from exposure to the pollution from these wells. The health impacts have high social and economic costs because they range from shorter life expectancy, preterm and low birth weight, and a variety of acute and chronic diseases affecting essentially all of the organ systems of the body. The activities of going to school and to work and engaging in daily life are adversely impacted, along with the overall health of the people over a shortened life expectancy.

CalGEM is required to estimate the social benefits from a proposed setback rule that reduces the air, water, and soil pollution in the nearby communities. A holistic evaluation integrates the large literature that already exists on the health impacts from the toxic pollution. It can be supplemented with an analysis of the health benefits from reducing ambient air pollution on people living near extraction activities, such as the research study being done by Gonzalez and colleagues at Stanford. Preliminary findings indicate that the health benefits from improved mortality when PM2.5 is reduced for inhabitants living within 2,500’ of extraction activities would be at least $360 million annually. The large social benefits from reducing the other toxins caused by extraction activities should be added to the benefits from reduced PM2.5.

The proposed setback rule is also likely to have a positive impact on worker and household productivity through reducing air pollution, which some economic experts suggest promotes rather than retard economic growth.

The cost of blue-collar job loss depends how many blue-collar jobs are required per active well. Employment of blue-collar workers is mostly for drilling new wells or reworking wells as they become less productive or have been idle. The blue-collar jobs in the extraction sector in California are not high-paying jobs, with the median hourly wage ranging from $16 to $30 (OES data). The job loss will depend on how many active wells are shut-down and to the extent this is offset by an expected increase in employment to plug and safely abandon California’s growing inventory of idle and orphan wells.

The social benefits to the impacted communities includes the other potential uses of the land and resources. The opportunity costs of land use, investment capital, and extraordinary industry tax subsidies must count against any alleged costs to the oil and gas industry. Most importantly, because investment decisions are private, these opportunity costs may exceed the social benefit of the impacted wells even before counting the other benefits of the rule.

The local pollution from oil and gas extraction activities affect the nearby communities, and the people are paying the external social costs with their health and well-being for the oil and gas to be extracted from wells within 2,500'. CalGEM's setback rule should protect the health of the nearby communities, and end their subsidizing the costs of oil and gas produced in California. This is one part of the overall social cost of producing and consuming oil and gas for energy, and future rules can address how to phase out fossil fuel production in California so the state reaches its climate goals.

Orphan Wells in California:

An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells

An Emerging Topic Report prepared by the California Council on Science and Technology

CCST
CALIFORNIA COUNCIL ON SCIENCE & TECHNOLOGY

A nonpartisan, nonprofit organization established via the California State Legislature — making California's policies stronger with science since 1988.

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An Independent Review of Scientific & Technical Information

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About CCST

The California Council on Science and Technology is a nonpartisan, nonprofit organization established via the California State Legislature in 1988. CCST responds to the Governor, the Legislature, and other State entities who request independent assessment of public policy issues affecting the State of California relating to science and technology. CCST engages leading experts in science and technology to advise state policymakers — ensuring that California policy is strengthened and informed by scientific knowledge, research, and innovation.

Note

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Acronyms and Abbreviations

AB	Assembly Bill
API	American Petroleum Institute (as in API number)
BOE	Barrel of Oil Equivalent
BLM	Bureau of Land Management
CCP	California Code of Civil Procedure
CCR	California Code of Regulations
CFR	Code of Federal Regulations
DOC	California Department of Conservation
Division	Division of Oil, Gas, and Geothermal Resources (the Division)
GAO	U.S. Government Accountability Office
HIDWAF	Hazardous and Idle-Deserted Well Abatement Fund
IQR	Interquartile Range
LMR	Liability Management Regime
PRC	California Public Resources Code
SB	Senate Bill
SLC	California State Lands Commission (the Commission)
Supervisor	State Oil and Gas Supervisor at the Division

Summary

In 2017, California was the fourth largest producer of crude oil and the fifteenth largest producer of natural gas among U.S. states (US EIA). There are about 107,000 active and idle oil and gas wells in California. At some point all of these wells will end their productive life and the operator/owner of the well will be required to carefully plug the well with cement and decommission the production facilities, restoring the well site to its prior condition. There is a large population of nonproductive wells in the state, known as idle wells, which have not produced oil and gas for at least two years and have not been plugged and decommissioned. Idle wells can become orphan wells if they are deserted by insolvent operators. When this happens, there is the risk of shifting responsibilities and costs for decommissioning the wells to the State.

There are policies in place to protect the State from the potential liabilities of orphan and idle wells. Operators are required to file indemnity bonds when drilling, reworking, or acquiring a well, to support the cost of plugging a well should it be deserted. However, the available bond funds are often not enough to fully cover the costs of plugging and decommissioning a well. In two recent insolvencies involving offshore facilities, Rincon Island and Platform Holly, the bonds recoverable by the State totaled about $32 million—well under the more than $100 million estimated cost to plug and decommission the wells at both facilities.

Issues with orphan wells are not limited to offshore wells. The vast majority of orphan wells in the state are located onshore. These wells represent potentially large liabilities for the State. In some cases, especially for older orphan wells, there may be no bond available. In an effort to prevent orphan wells, the operators of idle wells are required to pay fees or develop management plans to eliminate long-term idle wells. The Division of Oil, Gas, and Geothermal Resources (the Division) is in the process of updating these regulations and implementing new well testing requirements from recent legislation.

Concerned about the potential financial risks involved with idle and orphan wells and aware of similar problems in other parts of North America, the Division requested the California Council on Science and Technology (CCST) produce a study assessing the State's potential orphan well liabilities. Using existing data from the Division, we have conducted a rough estimate of potential future costs to the State for plugging and decommissioning orphan wells. We have also summarized recent studies that compare the policies and practices of California to other states and regions.

The preliminary analysis performed here finds that 5,540 wells in California may already have no viable operator or be at high risk of becoming orphaned in the near future. The likely plugging and abandonment costs for these wells, based on the State's historical experience with orphan wells, exceed the available bond funds by a factor of 10 or more. The State's potential net liability for these wells appears to be about $500 million. This

estimate ignores environmental or health damages that could be caused by orphan wells, which is a poorly understood category of potential impacts that is outside of the scope of this report and deserves greater study.

An additional 69,425 economically marginal and idle wells are identified here that could become orphan wells in the future as their production declines and/or as they are acquired by financially weaker operators. Increasing the financial security for these wells while they are still profitable may avoid enforcement challenges in the future. Idle Well Fee and Management Plan requirements may also reduce the stock of idle wells, but operators have less incentive to comply with regulations after wells cease production.

The total costs of plugging and abandoning all of the state's 106,687 active and idle oil and gas wells are found to be about $9.1 billion. This gives an unlikely worst-case scenario for the state's total costs. The share of this cost that is ultimately borne by the State (as opposed to operators) will depend on policy choices, market dynamics, and other factors. In comparison, the bond amounts currently held by the state for these wells cover only about $110 million. This study recommends several specific areas where more in-depth research will better inform future policy approaches.

Findings, Conclusions, and Recommendations

CCST Introduction

The California Council on Science and Technology (CCST) is a nonpartisan, nonprofit organization established via the Legislature in 1988 that is called upon by the State to conduct independent, scientifically rigorous studies to inform policy decisions. CCST studies are valued for their scientific and technical analysis, which undergoes a full peer review process to ensure that the information presented is accurate and technically sound.

This study was produced at the request of the Division of Oil, Gas, and Geothermal Resources (the Division) under the California Department of Conservation. It was researched and written by principal researchers and select CCST staff within a study team overseen by a Steering Committee Chair. The study team provides an appropriate range of expertise, a balance of perspectives, and no conflicts of interest.[1] This study was subject to a full and thorough peer review and the authors responded to all comments from reviewers.

CCST strives to produce reports through a transparent process to ensure that the final product is responsive to the questions of the sponsor, while maintaining full scientific independence. Transparency is achieved by engaging the sponsor in dialogue about the nature of the information needed and informing the sponsoring agency of study progress.

Language used in this study:
In oil and gas well terminology, there are many ways to say that a well has been properly plugged and/or that the remaining facilities have been removed and the site returned to its original condition: 'properly plug and abandon,' 'plugging and reclamation,' etc. In this study, we primarily use the term 'plug and decommission' to refer to the actual cementing or plugging of the well and restoration of the site.

1. See Appendix F for more information on the CCST study team selection and study process.

Chapter 1

Background

Among states in 2017, California was the fourth largest producer of crude oil (US EIA) and the fifteenth largest producer of natural gas (US EIA). The state's oil and gas fields are considered mature, and there is a growing population of nonproductive wells in the state.

The life cycle of oil and gas wells depends on a number of factors, the most important of which are production rates and energy market prices (Figure 1). A well can operate profitably for several years or decades depending on the rate of production and operating expenses. At low prices, or as production slows, operators may be inclined to shut down, idle, or hand off non-economic wells and leases. Once a well's productive life comes to an end, it must be carefully plugged with cement and its attendant production facilities decommissioned[1] to prevent any potential hazards. In California, this process is the operator's responsibility.

Under current rules (which have recently been revised), prior to drilling, reworking, or acquiring a well, an operator must file a security with the State in the form of an indemnity bond or other deposit. As of January 1, 2018, this bond cannot be released until the well is properly plugged and decommissioned. Indemnity bonds are an agreement between a principal (the operator), an obligee (the State), and a surety bond company (the surety) that protects the State in cases where operators do not fulfill their obligations to decommission a well—providing payment of the bond amount to the State. These bonds range in amount depending on the depth of the well and the number of wells to be covered. Current requirements for onshore wells range from $25,000 for a single well to $3 million for a blanket bond to cover all of an operator's wells. For offshore leases, there is a blanket $1 million bond required for drilling or modifying one or more wells. The historic and existing bond requirements as well as the availability and adequacy of bonds on file to cover the plugging and decommissioning of potential orphan wells are discussed in Chapters 2 and 3.

Finding 1-1: California requires well operators to obtain an individual or blanket indemnity bond prior to drilling, reworking, or acquiring a well or wells, not to be released until the well is plugged and decommissioned.

1. 14 CCR § 1760 "Decommission" means to safely dismantle and remove a production facility and to restore the site where it was located.

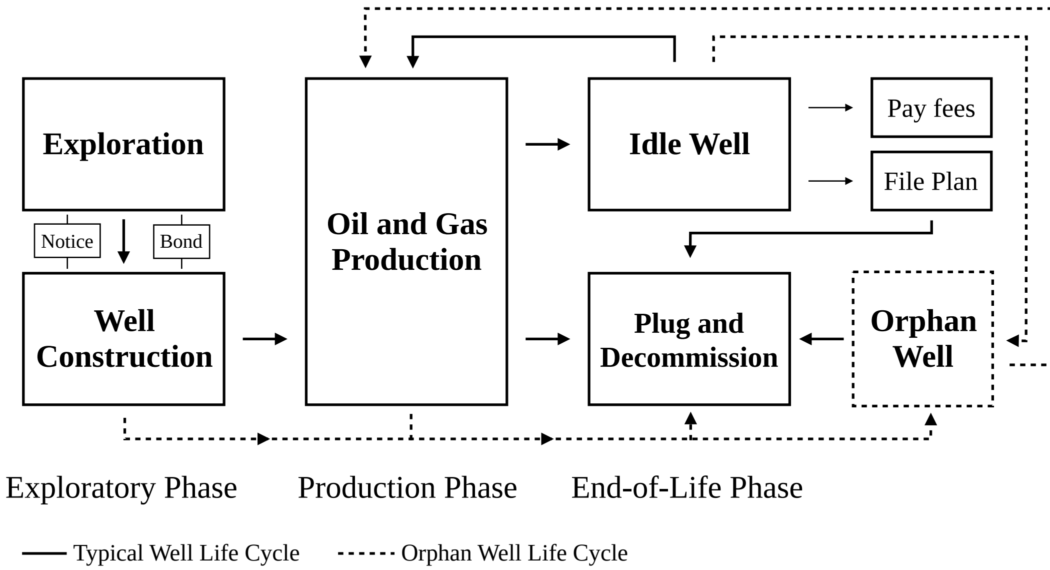

Figure 1. Typical well life cycle in California compared with the orphan well cycle. The initial exploratory phase encompasses the discovery and evaluation of reserves, drilling and completion of the exploratory well, and the determination that the well (field) can economically produce oil or gas. Prior to drilling, a notice of drilling along with an indemnity bond must be filed and approved. Production can last several years or decades depending on the size of the field and operating expenses. When the rate of production and sales fails to cover the expenses associated with maintenance and production, it has reached its economic limit. At that limit, the well may be considered a liability by the owner and may be plugged and abandoned, the production facilities decommissioned, and the indemnity bond recovered. Production can also be idled. A well is classified as idle when there is zero production, or other defined uses, for at least 24 consecutive months. Operators may eventually return idle wells to production, but while idle they may need to either pay annual idle well fees or file an Idle Well Management Plan. Finally, if a well is orphaned prior to plugging, the responsibilities of plugging and decommissioning the well may ultimately fall upon the State.

Finding 1-2: The amount of the required indemnity bond depends on well depth for individual bonds, the number of wells in the state to be covered for blanket bonds, and whether the well is located onshore or offshore. Bond amounts range from $25,000 for a single well to $3 million for a blanket bond covering multiple wells. The amount on file may also depend on when the well was last drilled, reworked, or acquired, and the bonding requirements at that time.

Of the approximately 229,000 oil and gas wells in California, about 122,000 have already been plugged. The remaining 107,000 of them are classified as either active or idle wells. California regulators consider a well to be an idle well if it has not produced oil or gas for

24 consecutive months.[2] Many of California's idle wells are long-term idle wells—wells that have been idle wells for eight or more years.[3] These idle wells are potentially at risk of becoming orphan wells. If not properly maintained or plugged, idle and orphan wells can present a potential environmental hazard. In some cases, these wells may provide a source for fluid and gas migration to unwanted zones. For example, they may leak oil, injected fluids, or formation water into nearby underground drinking water or surface water reservoirs, or release methane or other gases into groundwater or the atmosphere.

From idle to orphan

Wells are not always plugged and decommissioned immediately after production ceases. Operators often maintain wells in a nonproductive, idle state—either to preserve the option of resuming production in the future, or simply to defer the expense of permanently plugging the well.

It costs much less in the short term for operators to maintain a well in an idle state than to properly plug and decommission a well. In California, the required fees to maintain an idle well range from $150 per year to $1,500 per year. This approach also maintains the potential to return the well to production if energy prices increase. Although this "option value" from the ability to resume production can in principle be quite important, research in Alberta, Canada, has shown the decision to leave a well idle is more often driven by a desire to defer decommissioning costs on wells with little likelihood of resuming production (Muehlenbachs, 2015). Ultimately, some operators may declare bankruptcy in order to relinquish their leases and forfeit any requirement to plug and decommission the well, potentially leaving the costs to the governmental regulator.

Wells deserted by insolvent operators become orphan wells. Since orphan wells have no financially viable operator, the State may become responsible for plugging and decommissioning costs. At this point, the State may use the available indemnity bond funds on file, if any, to contribute toward the cost of plugging and decommissioning the well.

Orphan wells are a concern in every state and region that produces oil and gas. At the federal level, a recent study by the U.S. Government Accountability Office (GAO) made several recommendations to the U.S. Department of Interior in order to better protect against billions of dollars of potential decommissioning liabilities for offshore wells in the Gulf of Mexico (GAO, 2016). In Alberta, Canada, potential liabilities were estimated at between $129 million and $257 million for known orphan wells, with the total costs of well liabilities (when considering potential future insolvencies) estimated at up to $8.6 billion (Dachis et al., 2017).

2. PRC §3008(d) Wells that for 24 consecutive months have not produced oil or gas, or have not produced water used to stimulate production, for enhanced oil recovery, reservoir pressure management, or injection.

3. PRC §3008(e).

Recent offshore cases in California: Rincon Island and Platform Holly

In California, there have been several prominent cases where the State has had to take responsibility for an oil or gas field. Two offshore facilities in southern California and their associated wells recently became the responsibility of the State: Rincon Island in Ventura County and Platform Holly in Santa Barbara County. Offshore wells are much more expensive to plug and decommission than their onshore counterparts—often amounting to millions of dollars rather than thousands—and have a high priority to plug due to their environmental risk. For these reasons, operators of offshore wells are required to file higher amounts of security than what is required for onshore wells, either as part of their lease with the State or under Division regulations. This security, typically in the form of a surety bond, is intended to protect the State against losses in the event that the operator cannot afford the cost of plugging and decommissioning their wells. However, at Rincon Island and Platform Holly, the security amounts available were not enough for either facility. The State Lands Commission (the Commission) is responsible for managing leases on submerged lands in the state, including the three miles off the Pacific coast. The Commission requested \$108.5 million over three years from the state's General Fund to plug and decommission the wells (California State Lands Commission, 2018a), in addition to millions already appropriated to maintain and monitor the wells.

Finding 1-3: The amount of an indemnity bond may not be adequate to cover the actual plugging and decommissioning costs. For example, bonds on file from the leases at Rincon Island and Platform Holly, \$10 million and \$22 million, respectively, were a fraction of the estimated costs of over \$100 million for both leases.

In the case of Rincon Island, operated by Rincon Island Limited Partnership, the lease had not produced oil or gas since 2008. According to a staff report, Commission staff were prepared to recommend termination of the lease in August 2016 over regulatory violations (potentially risking environmental contamination) and other lease requirements. However, Rincon Island Limited Partnership filed for chapter 11 bankruptcy before the lease was terminated (Fabel & Blackmon 2018). After bankruptcy and eventual relinquishment of the leases, the Commission—with no responsible operator available to take over—entered into an emergency contract with a company to oversee the wells. The Commission also obtained \$8 million in a settlement agreement with prior lessee ARCO and worked to secure a combined \$10 million surety bond that was held by Rincon Island Limited Partnership.[4] The cost to plug the 49 wells and decommission the facilities at Rincon Island was estimated to be around \$50 million over three years (California State Lands Commission 2018a).

At Platform Holly, which had been non-operational since the Refugio Oil Spill in May 2015, the operator Venoco relinquished its leases of the South Ellwood Field in April 2017 and filed

4. According to a February 2018 SLC staff report (Fabel & Blackmon), the Division requested their combined \$350,000 bond be released to the Commission, which holds a \$9.65 million bond.

a petition for relief under chapter 11 bankruptcy, returning the lease and the platform's 32 wells to the Commission. The Division subsequently ordered that the Venoco wells be plugged and abandoned. When Venoco was unable to do so, the Commission called on and received Venoco's $22 million bond. This bond amount was intended to be larger. In August 2013, an amendment to the lease included provisions for increasing the bond amount incrementally by $4 million per year to eventually reach $30 million in September 2018. This amount was intended to be adjusted in 2025 and every 10 years to accurately reflect the full cost of Venoco's liabilities (California State Lands Commission, 2013).

In 1997, Venoco became the third operator assigned to the lease, following approximately 28 years by ARCO and 4 years by Mobil Oil Company. Under California law, the Division can pursue previous operators as far back as January 1, 1996, for plugging and decommissioning responsibilities. After calling on Venoco's bond, the Commission sought an agreement with the prior lessee, now ExxonMobil, to plug and abandon the wells. In August 2017, the Commission and ExxonMobil filed a letter of intent to discuss the plugging and abandonment of the Venoco wells and collaborated to assess needed repairs that would ease the plugging process. Meanwhile, the Commission hired a contractor to take over daily operations of Platform Holly. Anticipating a potentially lengthy process to reach a final agreement on the extent of liability and funding amount with ExxonMobil—and recognizing the urgency of the situation—the Commission requested $58.04 million from the General Fund to manage the platform and plug and abandon the wells (California State Lands Commission 2018a). In June 2018, the Commission and ExxonMobil entered into a Phase 1 agreement for plugging and abandoning the 32 wells on site, with provisions addressing contested wells modified by Venoco (California State Lands Commission and Exxon Mobil 2018).

In response to these recent offshore bankruptcies, the Governor signed legislation in September 2018 to specifically address any inadequate financial security of offshore oil and gas wells in California (SB 1147, Hertzberg).

The decommissioning of onshore wells

Though these recent cases highlight the more expensive and complicated nature of the offshore plugging and decommissioning process, most wells in California are located onshore. In fact, offshore wells account for just over 2% of all wells in California and, as of January 2018, there were only 19 offshore leases remaining in the state (California State Lands Commission, 2018b). No new offshore lease has been approved by the Commission since 1968.

Like their offshore counterparts in California, onshore wells can also be hazardous and expensive to decommission, especially in dense urban areas. In 2004, an orphan well leaked in a neighborhood in the city of Huntington Beach for several hours. An emergency rig was called in to plug the well (Division of Oil, Gas, and Geothermal Resources, 2011). In 2016, two buried orphan wells were discovered on Firmin Street in the residential Echo

Park neighborhood of downtown Los Angeles after reports of an odor coming from one of the wells. Drilled before 1903, these wells were deserted by their operators. The Division utilized industry funds from their orphan wells program to properly plug the wells. It cost the Division more than $1 million to plug the wells, according to its own estimates. The expense of such onshore projects, along with the sheer number of onshore wells and their location throughout the state, makes them a major point of concern for the State in terms of potential liabilities.

Finding 1-4: The vast majority (nearly 98%) of wells in the state are located onshore. The vast majority of idle wells in the state are also onshore.

Conclusion 1-1: Recent cases in California highlight the potentially expensive and complicated nature of plugging and decommissioning offshore wells and the difficulty of determining liabilities following bankruptcy. As most of California's wells are located onshore, it will be important to assess the potential liabilities for onshore wells in situations where idle wells may become orphan wells.

Considering these recent experiences and concerned about the potential cost and liabilities associated with plugging and decommissioning both existing orphan wells and wells that may become orphaned—which may include some of the thousands of idle and long-term idle wells—the Division asked CCST to assess these potential costs. CCST was also asked to look at the policies of other states and regions regarding orphan well management and cost recovery for how they could inform California policy. To accomplish these tasks, the CCST study team undertook a literature review and examined available datasets from the Division and elsewhere. Through meetings, investigations, and literature and data review, the CCST study team has drafted this report to address the questions and concerns of the Division.

Chapter 2

Relevant Laws and Regulations Governing Oil and Gas Wells in California

The statutory requirements and definitions relating to the operation of oil and gas wells in California are provided in Division 3 of the Public Resources Code (PRC) and Title 14, Chapter 4 of the California Code of Regulations (CCR), with primary responsibilities given to the Division of Oil, Gas, and Geothermal Resources (the Division), led by the state oil and gas supervisor (the Supervisor), under the California Department of Conservation (DOC).

The operation of oil and gas wells

There are numerous laws affecting the operation of oil and gas wells in California. The operator of a well is the entity who has the right to drill or operate a well.[1] Drilling new wells or the deepening or redrilling of existing wells requires a notice of intention, to be approved by the Supervisor or district deputy.[2] Alongside the notice of intention, operators must provide an indemnity bond, or a deposit in lieu of a bond,[3] for any well drilled or reworked, intended to protect the State against losses in case the operator cannot afford to plug the well. The bond can be released once the well is properly plugged and decommissioned. Operators must notify the Supervisor or district deputy when selling or transferring their wells or production facilities[4] and are similarly required to do so when they acquire a well or production facility. [5]

Bonding requirements

Bonding requirements for wells have changed over the years (Table 9). Initially set at $5,000 per well (Ch. 93, 1939), they have since increased in cost and been modified to account for well depth, idle status, location onshore or offshore, and number, allowing the use of blanket bonds for operators with many wells. Most recently refined by AB 2729 (Williams et al., 2016), operators are now required to obtain individual indemnity bonds when they drill, redrill, deepen, or permanently alter any well. Beginning January 1, 2018, these

1. PRC §3009 Person who either by ownership or lease has the right to drill, operate, maintain, or control a well.
2. PRC §3203.
3. CCP §995.710.
4. PRC §3201 When selling, exchanging, transferring, or otherwise disposing of their wells or production facilities.
5. PRC §3202.

requirements were also applied to any operator who acquires a well. As increased by SB 665 (Wolk, 2013), operators must file indemnity bonds with the Supervisor for either $25,000 for each well that is less than 10,000 feet deep, or $40,000 for each well that is 10,000 or more feet deep (Table 1).[6] A bond of $100,000 is also required for each Class II commercial wastewater disposal well.[7] The bond is specified to protect the state against all losses, charges, and expenses incurred in obtaining operator compliance with the provisions.

Table 1: Individual bonds

Well Depth	Amount
10,000 ft or more	$40,000
Less than 10,000 ft	$25,000
Class II disposal well	$100,000

Blanket indemnity bonds cover the drilling or modification of 20 or more wells at a time.[8] The blanket bond covers all of the operator's other onshore wells in the state. If the operator has 50 or fewer wells in the state, they must provide a bond of $200,000 to cover them all, or $400,000 for more than 50 wells. New upper level categories of $2 million for more than 500 wells, and $3 million for more than 10,000 wells, were added by AB 2729 (Table 2). These well numbers do not include any wells that the operator has already plugged. Another notable change resulting from AB 2729 is that, as of January 1, 2018, state law only allows indemnity bonds to be released upon proper plugging and decommissioning of wells rather than at the time of completion of the well.[9] This requires all necessary steps to ensure proper separation from underground or surface water.[10] For safety purposes, the Supervisor or district deputy may also order or permit the reabandonment of any well they suspect was not properly plugged or any well that is not visible or accessible.[11] Reabandonment is an operator's responsibility, except for a few scenarios in which the operator did plug and decommission the well in conformity with the requirements at the time.

Finding 2-1: Recent legislation revised California's indemnity bond requirements, requiring bonds for operators acquiring a well, increasing individual and blanket bond amounts, and requiring that a well be properly plugged and decommissioned before a bond is released.

6. PRC §3204.
7. PRC §3205.2.
8. PRC §3205.
9. PRC §3207.
10. PRC §3208.
11. PRC §3208.1.

Table 2: Blanket bonds

# Wells in State	Amount
More than 10,000	$3,000,000
501 - 10,000	$2,000,000
51 - 500	$400,000
50 or fewer	$200,000
Offshore	$1,000,000

Offshore wells

For offshore wells, there is a blanket $1 million bond required for drilling or modifying one or more wells located in submerged, ocean waters within the state's jurisdiction.[12] In addition, the entity who operates one or more of these offshore wells is required by the Supervisor to provide security to cover the full cost of plugging and decommissioning of the wells. However, there is an exception to this additional security in cases where a similar bonding agreement is part of the lease with the State, usually with the State Lands Commission, for offshore wells. The Commission tracks bonds for each of the 19 remaining offshore leases, which are as high as $30 million for a single lease (California State Lands Commission, 2018c). In September 2018, the Governor signed SB 1147 (Hertzberg), seeking to more adequately cover the cost of plugging and decommissioning offshore oil and gas wells.

Finding 2-2: In addition to the required offshore indemnity bond of $1 million, offshore wells require a supplemental form of security to cover the full costs of plugging all of the operator's offshore wells. However, these bonds may be filed as part of the operator's lease with the State Lands Commission, rather than as additional security with the Division.

Idle well fees and management

Recently, requirements from AB 2729 (Williams et al., 2016) increased annual idle well fees, based on the amount of time each well has been idle. The law also requires the operator of any idle well, even if that idle well is already bonded, to either pay the annual fee or file an Idle Well Management Plan to manage or eliminate their long-term idle wells. Prior to January 1, 2018, operators who already had an indemnity bond on an idle well or held a $2,000,000 all-inclusive blanket bond were exempt from these fees. Now, on an annual basis on or before January 31, operators must file a fee of $150 for each well that has been an idle well for 3 years or longer,[13] $300 for each well that has been an idle well for 8 years or longer, $750 for each well that has been an idle well for 15 years or longer, or $1,500 for

12. PRC §3205.1.

13. Since idle wells are wells that have not produced for 24 consecutive months, if a well is classified as an idle well for three years, it means the well has not been productive for five total years.

each well that has been an idle well for 20 years or longer (Table 3).[14] These fees go into the Hazardous and Idle-Deserted Well Abatement Fund (HIDWAF), which is continuously appropriated without regard to fiscal year for the plugging and/or decommissioning of wells or production facilities at hazardous or potentially hazardous sites. Hazardous wells and facilities are those that have been determined to be a potential danger to life, health, or natural resources and have no known operator responsible for plugging or decommissioning. If an operator fails to pay idle well fees for any of their idle wells, that failure may serve as conclusive evidence of desertion, for which the Supervisor can order the current operator to plug and decommission the well. Additionally, since the implementation of AB 1960 (Nava, 2008), if an operator has a history of violating the Division's regulations, they may be ordered to keep a life-of-well bond, covering the full estimated lifetime costs of their wells.[15]

Table 3: Idle well fees

Years Classified as an Idle Well	Annual Fee
20 or more	$1,500
15 to 19	$750
8 to 14	$300
3 to 7	$150

Finding 2-3: Recent legislation in California has increased idle well fee requirements and revised the requirements for the idle well management program.

Finding 2-4: Fees from the idle well program go into the Hazardous and Idle-Deserted Well Abatement Fund (HIDWAF), which is continuously appropriated without regard to fiscal year to support the plugging and decommissioning of hazardous or potentially hazardous wells and facilities.

Finding 2-5: Wells may be considered deserted and ordered plugged if the operator fails to comply with certain well regulations, including payment of idle well fees.

Finding 2-6: Since 2008, operators with a history of violating well regulations may be required to hold a life-of-well bond, covering the full estimated lifetime costs of the well and/or production facility, including plugging, decommissioning, and spill response, rather than a categorical indemnity bond based on well depth, or a blanket bond. According to the Division, no operator currently holds such a life-of-well bond.

14. PRC §3206.

15. PRC §3270.4: A life-of-well bond includes an amount adequate to plug each well and decommission each production facility and to finance a spill response and incident cleanup.

As an alternative to paying idle well fees, operators may file a plan with the Supervisor to manage or eliminate their long-term idle wells: operators with 250 or fewer idle wells must plug and decommission 4% of their long-term idle wells each year, operators with 251 to 1,250 idle wells must get rid of 5% of their long-term stock, and operators with more than 1,250 idle wells must get rid of 6% of their long-term idle wells each year (Table 4).[16] In each case, operators must eliminate at least one long-term idle well per year.

Table 4: Idle Well Management Plans

# Idle Wells	Annual Reduction of Long-Term Idle Wells*
1,250 or more	6%
251 to 1,249	5%
250 or fewer	4%

*In each case, operators must eliminate at least one long-term idle well per year

Idle well testing and management requirements

The passage of AB 2729 (Williams et al., 2016) required the Division to update its regulations relating to idle wells by June 1, 2018. It is in the process of doing so. The bill included idle well testing and management requirements to determine separation from drinking water sources; well mechanical integrity or appropriate remediation; and an engineering analysis for wells that are idle 15 years or more to see if they could return to production. If an operator does not remediate a well or fails to show that it could return to operation, then the operator must plug and decommission the well. If an operator fails to comply with these well testing requirements, it can be considered conclusive evidence of desertion.[17] The Supervisor is also required to present an annual report to the Legislature commencing on or before July 1, 2019, including the following:

1. A list of all idle and long-term idle wells and any status changes

2. A list of remaining orphan wells including identified idle/long-term idle wells that have become orphan wells and the costs and timeline for abandoning those wells

3. A list of all operators who have filed their long-term idle well plans.[18]

The Division is in the process of preparing this information.

District discretionary authority

The Supervisor and district deputy are also granted the authority to order the plugging and decommissioning of a well or the decommissioning of production facilities that are determined to be deserted. Credible evidence for desertion includes the operational

16. PRC §3206.

17. PRC §3206.1.

18. PRC §3206.3.

history, operator response, operator compliance with existing law, and other criteria[19] and are presumed to be deserted under a number of scenarios.[20] An operator can counter a presumption of desertion with credible evidence. If a well is deserted but the operator cannot pay for the costs of plugging and decommissioning the well, the Division can pursue previous operators as far back as January 1, 1996, as stipulated by SB 2007 (Costa, 1996).[21] If no responsible operator is identified, the Supervisor can plug and decommission the well, in line with their policies for plugging hazardous wells and facilities.[22]

As of July 1, 2018, the Division's expenditure authority for plugging and decommissioning hazardous or orphan wells and facilities was increased to up to $3 million per fiscal year (from $1 million) from the annually-assessed industry fees on production that fund the Division's operations (Lara 2017). [23] Beginning with the 2022-23 fiscal year, that amount will decrease to the previous amount of $1 million. Funds from idle well fees in HIDWAF (which are continuously appropriated without regard to fiscal year) are available for additional support. Alongside the increased expenditure authority, the Division is required to develop criteria for plugging and decommissioning hazardous or orphan (idle-deserted) wells and facilities. On October 1, 2020, the DOC is required to report to the Legislature the number of hazardous and orphan wells and facilities remaining and the estimated costs and timeline for plugging and decommissioning them. On October 1, 2023, the DOC must provide an update on actual costs, average costs per well and facility, the number of wells plugged and abandoned, the number of facilities decommissioned, the total projects completed, and any additional wells identified for plugging and decommissioning.[24]

Finding 2-7: The Division's expenditure authority for plugging and decommissioning orphan or hazardous wells and facilities was recently increased to up to $3 million per fiscal year until 2022, when it will decrease back to $1 million per year. With this expenditure authority, there are numerous reporting requirements to the Legislature regarding orphan and hazardous wells and facilities.

Conclusion 2-1: With the recent updates to idle well management and testing requirements, and the numerous reporting requirements, the State will gain a more comprehensive list of remaining hazardous and orphan wells and a better sense of responsible operators based on compliance with the updated idle well requirements.

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19. PRC §3237(a)(2).

20. PRC §3237(a)(3).

21. PRC §3237.

22. PRC §3250 - 3258.

23. See PRC §3258 for expenditure authority. Changes in expenditure authority may result in an adjustment to the rate that determines annual charges on oil and gas production as described beginning with PRC §3400.

24. PRC §3258.

Chapter 3

Quantifying Potential Oil and Gas Well Liabilities in California

This chapter uses administrative data from the Division to roughly estimate the potential future costs to the State to plug and decommission orphan wells. To do this, a simple screen was developed to identify wells that may already be orphaned or be at high risk of becoming orphaned in the future. The likely plugging and abandonment costs for these wells were benchmarked using historical costs for other wells plugged by the State. Finally, the available bond funds from each well's operator were considered to generate an estimated net cost to the State.

This chapter begins by describing the data provided by the Division and how this raw data was merged and cleaned to create the analysis dataset. Results are presented in three subsections focused on identifying orphan wells, understanding likely plugging costs, and calculating available bond funds. The final section of this chapter combines these pieces into an overall estimate of the State's potential net liabilities for orphan wells.

Data and descriptive statistics

Our analysis is based on administrative data on oil and gas wells provided by the Division, which provided information on 240,741 wells. We remove 12,093 well records with a status of "Canceled", which indicates permits that were never drilled, leaving 228,648 wells. This dataset includes plugged, active, and idle wells. The well types in the dataset include both oil and gas production wells and other related well types, such as injection wells. The data appendix provides more detail on the input datasets and how those raw data were used to build the final dataset.

Table 5 presents summary statistics for the analysis dataset. The median production rate across active and idle wells is just 2.7 barrel-of-oil-equivalents (BOE) per day.[1] The median year of first production is 1989 and 28% of the unplugged wells in the dataset are officially classified as "idle" by the Division.[2] These production statistics underscore the mature status of oil and gas fields in California. With few major discoveries in recent decades, producers are now focused on efficiently extracting remaining oil and gas from partially-depleted fields. Most wells are located onshore (about 98%), accounting for 95% of production during 2013–2017. Of the 1,454 operators with any active or idle (unplugged) wells, 1,099 operate only idle wells. At the same time, 91% of idle wells belong to operators that also

1. One BOE represents one barrel of crude oil or 6,000 cubic feet of natural gas.
2. We use first observed production because drilling or completion dates are missing for a large share of wells.

have active wells. As shown later, this reflects the fact that a few companies operate a large share of all wells.

Table 5: Summary statistics for analysis dataset

Wells	228,648
Plugged	121,961
Active/Idle	106,687
Among Active/Idle Wells	
Median Daily Production (BOE)*	2.7
Median Year of First Production*	1989
% of Wells Offshore	2.3
% of Production Offshore	5.3
% of Wells Idle	28
Operators with Active or Idle Wells	1,454
Operators with only Idle Wells	1,099
% of Idle Wells Belonging to Operators with some Active Wells	91

*Starred values calculated using well types OG, GAS, and Multi.

Figure 2 shows average monthly production over the life of a California well. These curves were constructed using all oil and gas wells entering production between 1980 and 2017. The figure shows how production declines over the life of the well due to reservoir depletion. This phenomenon of declining production is central to the orphan well problem. Near the end of a well's productive life, it generates little revenue that can be used to pay for plugging and decommissioning. Consistent with the mature status of California's oil and gas fields, the figure also shows that wells have become less productive in recent decades. For wells drilled in recent years, initial production is lower and declines are steeper than for wells drilled during the 1980s. Production in the fifth year of the life of a well drilled during the 2000s or 2010s is about half of fifth-year production of a well drilled during the 1980s or 1990s.

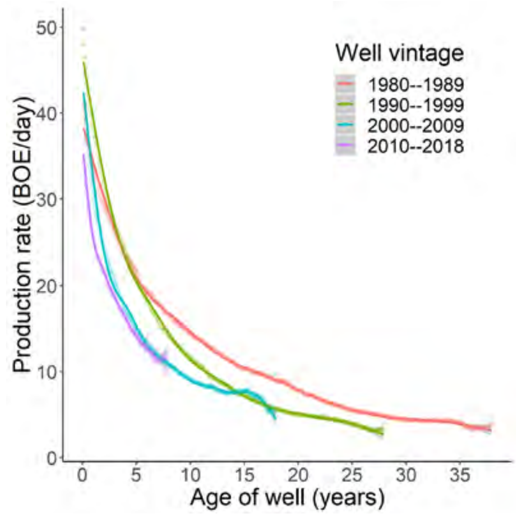

Figure 2. Average production by age of well and decade drilled. This figure shows the average production rate (in BOE/day) in each month of a well's productive life. The four colors represent averages for wells drilled during each decade since 1980. The fitted lines represent smoothed non-parametric fits and 95% confidence intervals (in gray). The first month of a well's productive life is defined as the first month of non-zero production.

RESULTS

Identifying potential orphan wells

Historically, there has been little monitoring of the solvency of operators of idle oil and gas wells in California. While the State maintains a comprehensive list of idle wells, the share of these that are orphan wells is unknown. An orphan well is defined here as an idle well for which no responsible operator exists to undertake plugging and decommissioning.[3] The first step in this analysis was to develop a rough screen for wells that may already have been orphaned or that risk becoming orphan wells in the near future. This approach is based on recent production from the well, as well as production by the operator from other California wells. Six categories of wells are defined, which are summarized in Table 6.[4]

3. Idle wells by definition exclude plugged wells, which are no longer producing but have been properly plugged and abandoned.

4. The statutory definition of an idle well also exempts from idle status wells that produce water to be used in tertiary production methods. Accounting for water production has little practical effect on the number of wells in each category in our analysis.

Table 6: Categorization of oil and gas wells

Active and Idle Wells	
Likely Orphan Wells	2,565
High Risk of Becoming Orphan Wells	2,975
Other Idle and Marginal Wells	69,425
Higher-Producing Wells	31,722
Plugged Wells	
Plugged before modern requirements	41,390
Plugged after modern requirements	80,571
Total	228,648

In this study, wells with no production or injection in the past five years that also belong to operators with no California production or injection in the past five years are considered to be "likely orphan wells." There are 2,565 wells in this category. The lack of observable activity by the operators of these wells is an indication that they may have no viable operator, so the State may bear the costs of plugging and abandoning these wells.[5] The next category in the screen is "wells at high risk of becoming orphan wells," which includes 2,975 wells. These are wells with no production or injection activity during the past five years, where the responsible operator is currently active in California but is small and operates primarily idle and marginal wells. Specifically, this group includes idle wells where the operator's average production rate across all wells is less than five BOE/day, and the operator has fewer than 1,000 actively producing wells. We focus on small operators because research in other states suggests small operators are more likely to orphan wells (Boomhower, in press) and because these small companies are more difficult to recover costs from in the event of default due to the high fixed costs of such collection efforts.

The third category of orphan well risk includes all other idle and marginal wells, where we define marginal wells as wells producing fewer than five BOE/day. It also contains currently active injection wells.[6] This category includes 69,425 wells. Many of these wells belong to a few large operators that are responsible for thousands or tens of thousands of primarily low-producing or idle wells.[7] These major producers likely face lower risk of insolvency than smaller producers. In addition, if they do become insolvent, collection efforts may be more cost-effective because the State would quickly notice such a bankruptcy and because the fixed costs of legal efforts can be spread over the firm's many wells. At the same time, the risk of bankruptcy exists even for large

5. While we use five years of inactivity as our cutoff, many of the wells and operators in this category have been inactive for much longer—in some cases, decades.

6. We include all active injection wells in this category because of the lack of a clear method for identifying which active injection wells are economically marginal. Of the 69,425 wells in this category, 13,057 are injection wells.

7. Aera Energy, Chevron U.S.A., and California Resources Production Corporation together account for 57% of the 33,288 wells that have been inactive for five or more years. These same three operators are responsible for 60% of all oil and gas wells in California. The largest 10 operators account for 90% of inactive wells and 82% of all wells.

producers. A single bankruptcy among one of these large companies could potentially create a large number of orphan wells, at great cost to the State.[8]

The fourth category includes wells that currently produce more than five BOE/day.[9] These higher-producing wells are currently at low risk of becoming orphan wells. Even if their current operators were to become insolvent, other companies would likely find it profitable to take over these wells and continue production.

The final two categories include plugged wells. California implemented modern requirements for well plugging to protect groundwater in February 1978. The 41,390 wells plugged prior to these requirements may not have been plugged to current standards, increasing the risk that they will need to "re-abandoned" in the future. The remaining 80,571 wells were plugged during the modern regulatory period.

It is important to note that this coarse categorization is a rough screen meant to assess the approximate magnitude of the orphan well problem in California using the best available data from the Division. The thresholds used in the analysis to define marginal wells and to categorize operators are by necessity somewhat arbitrary. In the appendix, we investigate the sensitivity of our categorizations to changes in these category thresholds. More broadly, this coarse approach is substantially less detailed than would be required to make legal determinations about the status of any given well. It is also less sophisticated than approaches used by regulators in other jurisdictions (e.g. Alberta, Canada), which rely on detailed, company-specific financial information that is not tracked by the Division.

Another important note about this screen is that oil and gas wells commonly transfer between operators as production decreases, meaning that a marginal well at low orphaning risk today could change risk categories if sold to a less robust operator. Our calculations using data from the Division imply that a typical California oil and gas well has passed between about three different operators by the time it reaches ten years old. While California law makes former operators jointly liable for plugging and decommissioning costs of wells sold after 1996, recovering costs from previous operators may be costly and time-consuming in practice. Thus, in coming years or decades, some of the wells in the "Other Idle and Marginal Wells" and "Higher-Producing Wells" categories could ultimately become orphan wells as they transfer between operators. Despite these limitations, this coarse categorization is useful for approximating the current orphan well problem in California given the available data.

8. The orphan well risk posed by some large operators depends partly on complicated and currently unsettled legal questions. For example, some of these firms are subsidiaries of or receive investments from international corporations. There seems to be disagreement about the degree to which those parent firms would be held liable for costs created by their subsidiaries. In addition, large companies may also consider reputational consequences in addition to direct financial penalties.

9. A common alternative threshold for marginal wells is ten barrels per day. Our conversations suggest that many wells in California operate profitably at lower levels of production, and so we use five BOE/day as our cutoff for economically marginal wells. This is a simplification reflecting our coarse analytical approach. The actual economic limit for any given well depends on field-level production costs, output prices, and other factors.

Finding 3-1: A coarse analysis of readily available information from the Division suggests several thousand wells in California are likely orphan wells or are at high risk of becoming orphan wells in the near future.

Finding 3-2: Tens of thousands of additional idle and low-producing wells could become orphan wells in the future if they are acquired by a financially weak operator or there is a prolonged negative shock to the oil and gas industry. The likelihood of these wells eventually becoming orphan wells depends in part on the practical enforceability of California's rules that make previous well operators jointly liable for decommissioning costs. Old wells plugged prior to modern standards may also pose some risk.

Recommendation 3-1: Refine predictions of wells at risk of becoming orphaned. A more detailed analysis could consider additional factors such as operator financial information, field-level production costs, and output price projections.

Recommendation 3-2: Study the ownership history of orphan wells and wells at high risk of becoming orphan wells. Such research will identify the share of plugging and decommissioning costs that may be recoverable from previous operators. It will also increase understanding of well ownership dynamics, which are thought to involve wells moving to smaller, higher orphan risk operators as production rates decrease.

Finding 3-3: Improved measurement and data management will be important for assessing the orphan wells problem in more detail and monitoring the effectiveness of policy responses.

Figure 3 shows the broad geographic distribution of likely orphan wells and wells at highest risk of becoming orphan wells. The distribution of these wells is similar to the overall geographic distribution of oil and gas activity in the state. Figure 4 shows more detail for southern and central California.

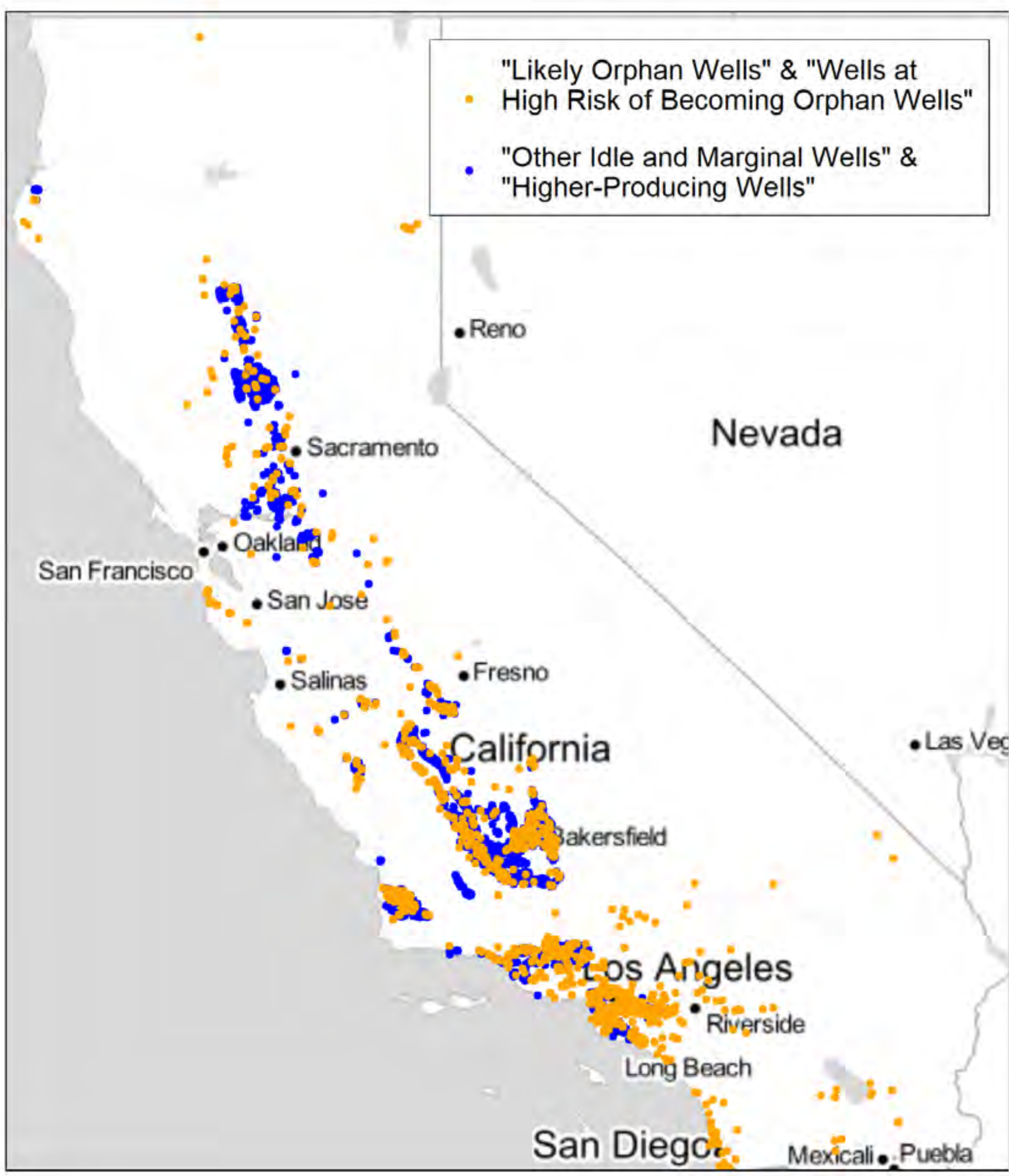

Figure 3. Statewide map of potential orphan and other wells.

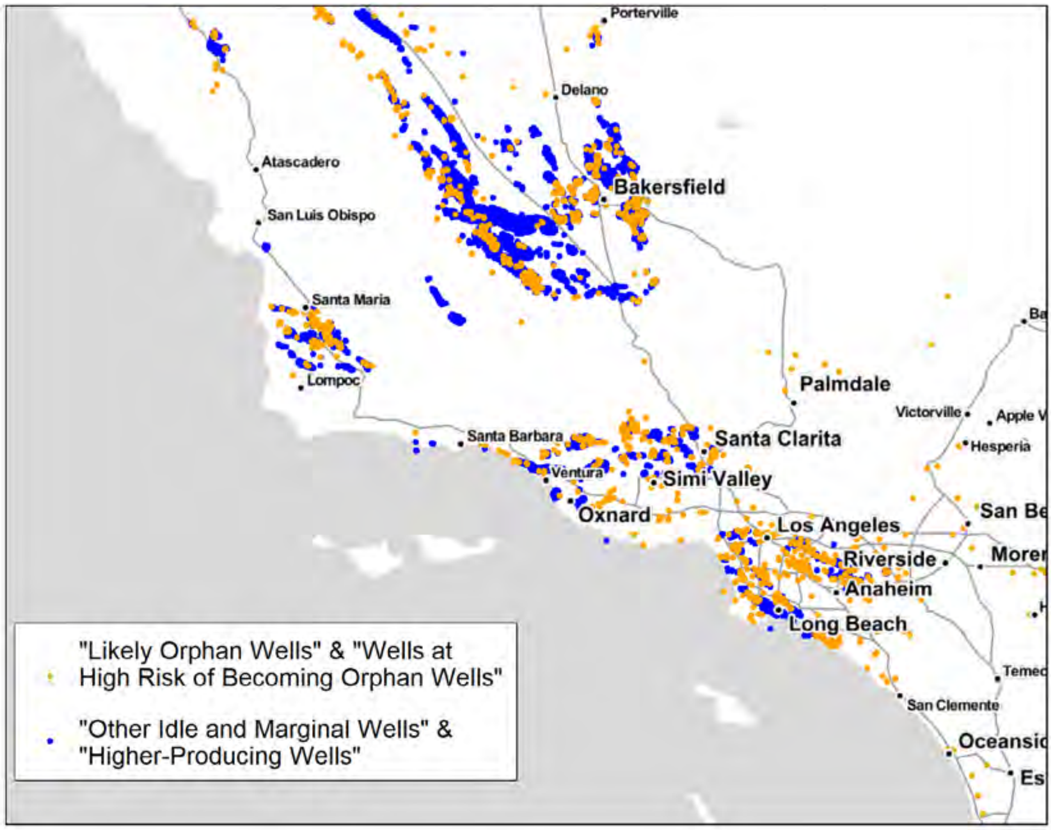

Figure 4. Detailed map of Southern California.

Finding 3-4: The likely and potential orphan wells we identify are located throughout the state matching the overall geographic distribution of oil and gas activity, with greater concentrations near Kern County and Los Angeles County.

Potential costs faced by the State

The costs ultimately imposed on the State by orphan wells depend on plugging and decommissioning costs, as well as any amounts that can be recovered from responsible operators through claims on bond funds. This section considers these elements. A category of potential costs that we do not consider is possible environmental or health damages due to pollution from orphan wells. These impacts are poorly understood and are the subject of ongoing research by geologists and engineers. One priority for future research is to determine the economic significance of these potential damages.

Finding 3-5: The risk of environmental or health damages from orphan wells is poorly understood but may be significant in some cases.

Recommendation 3-3: Investigate the potential environmental impacts of orphan and idle wells in California. Possible impacts may include groundwater contamination, human health impacts, and other issues.

Per-well plugging costs

The Division provided us with information on plugging and abandonment costs for a subset of onshore wells that have been plugged at State expense since 2013. In the various records provided by the Division, we identified 86 wells where expenditures were reported at the individual-well level.[10] The reported costs are the amounts paid by the Division to private contractors to plug and abandon each well. These contracts are negotiated on a case-by-case basis and the exact services procured can vary. Most of the contracts we were able to review included both well plugging and minimal surface restoration.[11] Projects involving more complex surface remediation would likely be costlier.

The average contract cost in this sample is $68,000 per well. The range of costs is large, with a minimum value of $1,200 and a maximum of $391,000. Figure 5 shows this variation is partially explained by district-specific factors. The four box plots describe plugging costs for wells in each the Division district: southern, northern, inland, and coastal. The median plugging cost in the Southern district, which includes urban areas near Los Angeles and Long Beach, is about three times greater than median plugging costs in the other districts.

10. The Division also provided aggregate expenditures on well plugging for an additional several dozen wells. We focus on individual well expenditures in our main analysis so that we can analyze geographic and other variation in costs. Including the aggregate spending on the additional wells has little effect on our estimate of overall average cost.

11. For example, one fairly typical contract stipulates that in addition to plugging and abandonment of the wellbore, "[A] ll equipment, casing, or junk that requires removal to implement restoration to lawful conditions shall be removed and properly disposed of in accordance with environmental laws… All liquid wastes shall be removed and properly disposed of at the nearest approved site... [and] The surface at the site shall be restored."

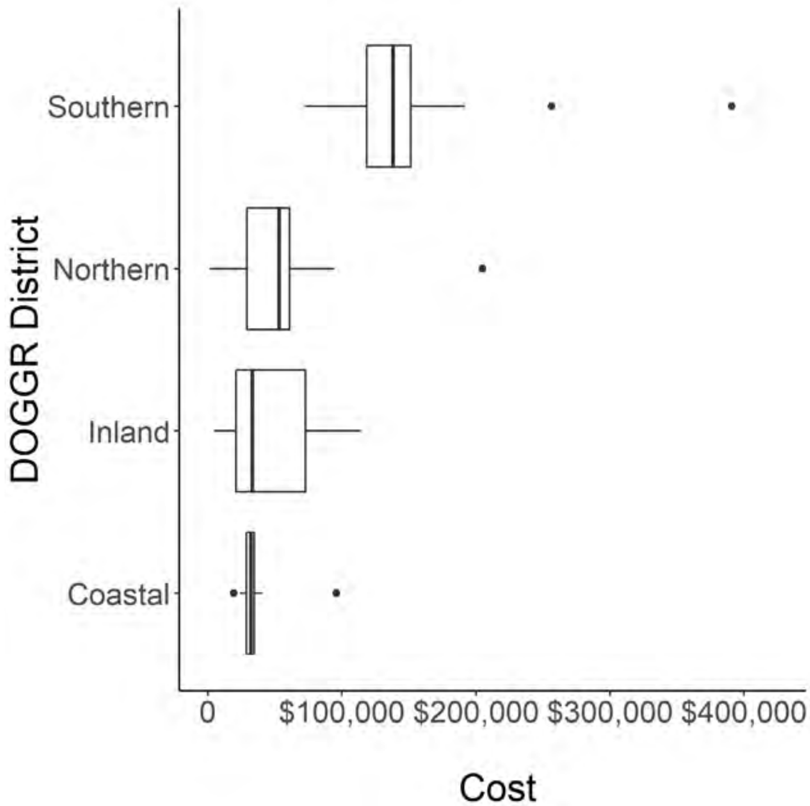

*Figure 5. Well-level plugging costs by district. Each of the four panels shows a box-and-whiskers plot for well-level plugging costs in the sample of 86 recent plugging contracts provided by the Division. The thick vertical line indicates the median; thin vertical lines show the interquartile range (i.e., the 25th and 75th percentiles). Black dots represent outliers (values outside of the interquartile range (IQR) by more than 1.5 * IQR).*

Figure 6 explores this variation in more detail. Panel (a) plots plugging costs against the date that the well was first drilled. Panel (b) plots plugging costs against population density. Older well ages and greater population densities are correlated with higher plugging costs. With this small sample of wells, it is difficult to disentangle correlation and causation. The Southern district wells in our small sample, which tend to be high cost, are located in more densely-populated areas and are older than average. Both age and population density have been reported to increase plugging and abandonment costs by Ho et al. (2018).[12] We also attempted to study the relationship between historical plugging costs and well depth but

12. Ho et al. (2018) provides a thorough and valuable summary of plugging costs across states, as well as detailed regression analysis of plugging costs using a sample of about 5,000 wells in Kansas. Their reported plugging cost for California is $31,000. That estimate is based on 113 wells in the Division's former District 2, which roughly corresponds to the coastal district in the Division's current four-district system. We find that incorporating costs from other districts yields a higher estimate because the other districts are systematically more expensive.

were limited by the availability of depth data, as we describe in Appendix B3.

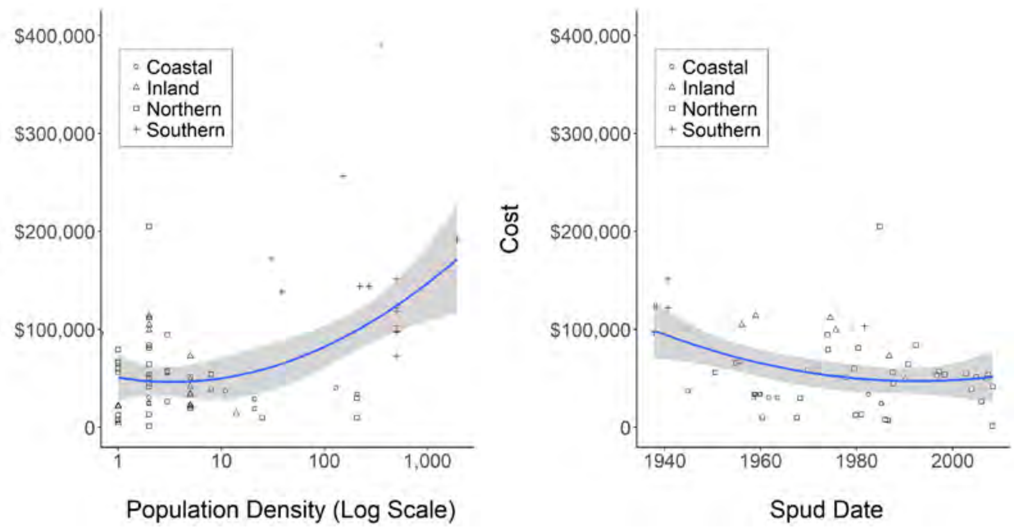

Figure 6. Variation in plugging and abandonment costs. These figures examine variation among the 86 wells with available information on plugging cost. The blue line and gray region indicate a quadratic fit and 95% confidence interval. Marker shapes indicate the four Division districts. Spud date is the date that drilling began. Spud dates were missing for 30 wells, so these are omitted from panel (b).

With a larger sample of plugging costs, determinants of California plugging costs could be investigated in more detail with regression analysis. Such analysis may be possible in the future using data from an industry source, or after the state accumulates cost records for future contracts. Given the limited data currently available, plugging costs for wells in each district were instead modeled using district-level averages. These average costs along with the number of observations for each district are in Table 7.[13]

13. All 86 of the well-level cost records provided by the Division are for onshore wells. Later in this section, when we consider future plugging costs, we use a placeholder estimate of $1.5 million for each offshore well based on the approximate per-well costs of plugging and decommissioning at Rincon Island and plugging and abandonment at Platform Holly (California State Lands Commission 2018a). While the large majority of idle wells are onshore, future analyses should consider offshore well costs in more detail.

Table 7: Average onshore plugging and abandonment costs by district

District	Observations	Average Cost
Southern	17	$152,000
Northern	32	$51,000
Inland	17	$47,000
Coastal	20	$40,000
Total	86	$68,000

Finding 3-6: Based on a small sample of well-level plugging costs, the statewide average cost to plug and abandon an onshore orphan well is $68,000. Costs in the densely-populated Southern district near Los Angeles are about three times higher than in other regions. Additional surface reclamation costs may be required for some wells.

Recommendation 3-4: Track expenses for orphan well plugging and surface reclamation at the individual well level in a centralized database. This will allow for more detailed understanding of the determinants of plugging and decommissioning costs, and thus more accurate cost predictions for future orphan wells.

Available bond funds to offset these costs

The Division collects performance bonds from oil and gas operators to align operator's incentives for plugging and decommissioning, and to offset these costs in the event that the operator does not perform their responsibility. This analysis suggests the effective amount of these bond funds is small compared to the predicted plugging costs calculated above. The Division provided information on bonds for all California oil and gas operators. Summing over all of the bonds for operators in the dataset, the total bond funds available to plug and abandon wells in California are about $110 million. Dividing by 106,687 active and idle oil and gas wells, this implies an overall average of just over $1,000 in available bond funds per well. Of course, the actual bond amounts available for each well depend on the bond posted by that well's operator, which are discussed below. But this simple average across all wells illustrates the rough size of bonds relative to the costs of plugging and decommissioning.[14]

The effective bond coverage for every well in California is calculated by dividing each operator's total bond amount by that operator's number of active and idle wells. Figure 7 describes these effective bond amounts for operators of different sizes. Effective bond amounts tend to be larger for operators with fewer wells, because blanket bond rules

14. The dataset provided by the Division does not include some bonds for offshore wells that are held by the State Lands Commission instead of by the Division. Many offshore platforms in California have bond coverage with the State Lands Commission of $20 million or more per platform, meaning that offshore bond coverage is substantially higher than onshore (though decommissioning costs are also substantially higher).

allow larger operators to post small bond amounts per well operated. Regardless of operator size, however, effective bond amounts are well below the predicted plugging and decommissioning costs discussed previously. Blanket bonds are one reason that these effective bond amounts are low. A second reason is that until recent increases, bond requirements in California had been quite limited.[15] Importantly, some California operators may be grandfathered in under prior bond requirements unless they have since undertaken significant rig work or acquired additional wells, or may have had their bonds released prior to plugging and decommissioning under old requirements. That means some operators of old wells in California may have no or very small bonds.[16]

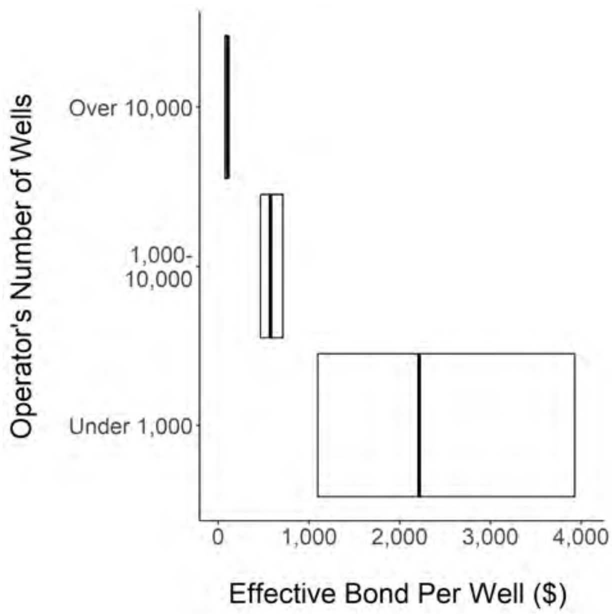

Figure 7. Available bond funds per well, by size of operator. This figure shows the median, 25th percentile, and 75th percentile of effective bond amount for wells with operators of different sizes. Effective bond amount is calculated by dividing each operator's total bond amount by the operator's total number of active and idle wells.

Finding 3-7: The bond amounts available to pay for plugging and decommissioning vary according to operator, but in almost all cases these amounts are substantially lower than the predicted costs.

15. As of January 1, 2018, bonds cannot be released until a well is properly plugged and decommissioned. However, prior to this, bonds could potentially be released upon completion of a well, prior to it being plugged and decommissioned.

16. The Division's records imply that 1,168 operators of active or idle wells have zero bond coverage. Together these companies account for about 3,350 wells.

Idle well fees and idle well management plans

As of 2018, California increased the fees it charges to operators of wells that have been idle for more than two years. Idle well fees provide additional revenue that can be used to fund the costs of plugging orphan wells. Chapter 2, Table 3 shows the current fees are small compared to the costs of plugging wells. For wells that have been idle less than 15 years, the fees are $300 per year or less and thus do little to offset plugging costs.[17] Fees are higher for wells idle longer than 15 years, eventually maxing out at $1,500 per year for wells idle for 20 years or more. These higher fees may contribute more meaningfully to revenues.

Using the Division's Idle Well List, we calculated the fees that would be required for each well, assuming the operator chose not to develop an Idle Well Management Plan.[18] This calculation implies an upper bound on idle well fees of about $16 million per year. The actual amount of idle well fees assessed will be smaller, since some operators will develop Idle Well Management Plans and thus avoid these fees, as explained in Chapter 2. In 2018, the actual amount of idle well fees that operators chose to pay was just under $4 million.

It is also important to note that idle well fees are only collectible while the well still has a viable operator. Fees assessed against defunct operators will not be paid. This is potentially significant because of the increase in idle well fees with years idle. In our calculation, almost two-thirds of the $16 million in possible idle well fee revenue comes from wells idle over 20 years. It may prove difficult to collect fees from operators of these very long-time inactive wells. At the time of this study, there were 2,296 idle wells whose operators had not responded to 2018 idle well letters, or could not be located to send the letter. In comparison, an advantage of bond requirements is to collect financial security at the outset of production, so that funds are guaranteed even if the operator is no longer viable.

The new Idle Well Management Plan (IWMP) requirements also have the potential to reduce the number of wells that may become orphan wells in the future. One additional benefit of the new regulation is to create an annual mechanism to verify the continued viability of operators. Failure to pay idle well fees or file an IWMP allows the Division to immediately identify legally deserted wells, a process that previously may have taken years of administrative effort. An important priority for future analysis will be to evaluate the contributions of idle well fees and the new Idle Well Management Plan requirements to offset orphan well liability and the number of wells at risk of becoming orphan wells. Such an analysis will have to consider the length of time wells are likely to be kept idle before being plugged by the operator or orphaned, the State's success in collecting idle well fees

17. Using the fee schedule from Chapter 2, Table 3, a well kept idle for 14 years before being orphaned would contribute $2,850 in idle well fees. Compare this to the average plugging cost in Table 7 of this chapter, which is $68,000.

18. The statutory definition is "any well that for a period of 24 consecutive months has not either produced oil or natural gas, produced water to be used in production stimulation, or been used for enhanced oil recovery, reservoir pressure management, or injection" (PRC § 3008(d)).

from operators, and other factors.

Finding 3-8: Idle well fees may offset some of the State's eventual liability for orphan wells. A rough calculation suggests that this contribution would be small with the current fee schedule.

Recommendation 3-5: Leverage the new annual Idle Well Fee/Idle Well Management Plan requirement to yield a more detailed count of wells without viable operators. Failure to file the annual idle well fees or an idle well management plan can serve as legal evidence of desertion.

Do plugging and abandonment requirements reduce option value from potential future production?

A common challenge in analyzing and regulating idle wells is understanding whether wells are kept idle because the operator has a reasonable expectation of eventually resuming production, or is simply deferring plugging and decommissioning costs. If it is the former, regulations forcing the well to be plugged create additional economic costs in terms of foregone option value. Plugging the well today increases the cost of resuming production in the future if prices or technology improve. It is impossible to know any individual operator's expectations about future production, but we can use historical data on idle wells to understand the average likelihood of returning to production after a given interval with no production. The most sophisticated existing economic research on this question is Muehlenbachs (2015), which considers idle oil and gas wells in Alberta, Canada. That study concludes that most long-term idle wells are unlikely to return to production even with large increases in output prices or improvements in production technology. Given appropriate data, such a study could be done specifically for California. Appendix B describes a first pass at this type of analysis for California using the data readily available for this study, and describes what would be required to study this question in more detail.

Overall summary of potential orphan well costs

Table 8 summarizes the State's potential liability for orphan oil and gas wells. The "Cost" column presents the total predicted plugging and abandonment cost for wells in each group, based on the district-specific average plugging costs discussed earlier in this chapter. The "Available Bonds" column sums up the total bond funds available for wells in each category. The "Net Liability" column shows the difference, which is the State's potential liability for orphan wells. All dollar values are rounded to the nearest million dollars. For the 2,565 wells we identified as "likely orphan wells", the aggregate predicted plugging cost is about $308 million. These wells are concentrated near Los Angeles and Long Beach, where plugging costs are systematically high. For comparison, the Division's annual budget for orphan well remediation projects has historically been about $1 million per year (though a recent appropriation increased that amount to $3 million per year for three years). The costs of the "likely orphan wells" are partially offset by about $10 million in available bond funds for these wells. That leaves about $298 million of the projected costs of these wells with the State. The group of "wells at high risk of becoming orphan wells" would add another $230 million in net costs to the State if they were all to become orphan wells, for a total potential liability of about $528 million across these two groups.

Table 8: Total potential orphan well costs among active and idle wells

Group	Wells	Cost (M)	Available Bonds (M)	Net Liability[19] (M)
Likely Orphan Wells	2,565	$308	$10	$298
Wells at High Risk of Becoming Orphan Wells	2,975	$246	$16	$230
Other Idle and Marginal Wells	69,425	$5,287	$53	$5,234
Higher-Producing Wells	31,722	$3,385	$27	$3,358
Total	106,687	$9,226	$107	$9,120

After these two groups, there are 69,425 remaining idle and marginal wells. In the unlikely event that 100% of these remaining wells were to become orphan wells, the additional net liability to the State would be about $5.2 billion. While this scenario is unlikely, the number of wells in this category means that the State faces large possible costs, particularly in the event of a prolonged negative shock to the oil and gas industry. Notably, the available bond coverage in the "other idle and marginal wells" category is lower on a per-well basis than in the previous two categories. This reflects the fact that many of these wells are operated by large companies with blanket bonds covering thousands or tens of thousands of wells.

After adding in the 31,722 high-producing wells, the total net cost to the State if it were to have to plug all active and idle California oil and gas wells would be about $9 billion. This total cost estimate is interesting not only as an unlikely "worst-case" scenario for state plugging liability, but also as an estimate of the total plugging and abandonment liability facing the California industry (regardless of whether it is borne by companies or the State). Over the longer run, as these wells decrease in production and potentially change hands between operators, the ultimate share of these wells that are responsibly decommissioned by their operators will depend on policy decisions as well as market fundamentals.

19. This net liability figure ignores offsetting revenues earned through idle well fees, as discussed in this chapter. Our analysis suggests these fee revenues are likely small compared to plugging costs, but further study of idle well fee revenues is required, as we describe.

This summary calculation omits an additional difficult-to-quantify financial risk posed by 121,961 wells that have already been plugged (see Table 6). The plugging and abandonment procedure must provide an effective isolation of the well fluids all along the well. Wells plugged according to older technologies and regulations may still pose some risk of contamination. Table 6 shows that 41,390 wells were plugged prior to modern plugging requirements. The precise risk posed by these older plugged wells is unknown.

Conclusion 3-1: If all of the roughly 5,000 wells that we identify as having the highest orphaning risk were to become orphan wells, the State's net costs after subtracting out bond funds could be about $500 million. The total net difference between plugging costs and available bonds across all oil and gas wells in the state is about $9.1 billion.

Recommendation 3-6: Study potential changes to blanket bond rules that would increase the effective per-well bonds for economically marginal wells. The Division should consider whether securing larger effective per-well bonds while wells are still profitable would avoid enforcement challenges once wells become idle.

Recommendation 3-7: Use the results of a more detailed investigation beyond the limited scope of this study to conduct an economic analysis of policy alternatives. The Division should identify specific policy changes with the greatest promise to manage costs from existing orphan wells and to efficiently regulate the number of additional orphan wells going forward.

Chapter 4

The Policies and Practices of Plugging and Decommissioning in Other States and Regions

Regulation overview: California in comparison with other states and regions

Ensuring that state policy adequately manages idle and orphan wells and their potential costs to the state is difficult to achieve. With an annually increasing inventory of historical wells—some many decades old—which for one reason or another require some form of remediation, most states have struggled to ensure they are able to adequately manage their well populations.

Most states regulate at least four principal aspects of potential or actual well decommissioning:

1. Financial assurance
2. Idle (or inactive) well status
3. Plugging and restoration
4. Notification, inspection, and approval

California is comparable to many other states in this regard. Like most regions, California's regulations have not been entirely sufficient to effectively monitor the scope of the orphan well problem, nor to ensure adequate financial resources to plug them. However, the State has been proactive in recent years and taken numerous steps that make its current financial assurance requirements among the strictest in the nation. Many other states and regions are in the process of re-evaluating their own orphan well management, and it remains to be seen whether and to what extent they choose to emulate the approach taken by California.

Finding 4-1: Relative to other states, California has been proactive in enacting some of the strictest financial assurance requirements in the nation, although the requirements still do not cover the full costs of plugging orphan wells.

Finding 4-2: Many states and regions have been forced to re-evaluate their regulations and financial assurance systems for orphan wells in recent years due to challenges in funding orphan well plugging.

Financial assurance

In every state, operators have to provide some form of financial assurance for a well at the time that it is drilled. This assurance is intended to cover or mitigate the eventual costs of plugging the well and/or environmental impacts caused by the well, in the event the operator at the time the well is terminated is unable or unwilling to do so. The type and scope of the assurance has changed considerably over time, with states attempting to ensure the most effective way to cover the price of decommissioning wells. Some states also express concern that operators, particularly smaller ones, may be less willing to invest in wells in states where more costly financial assurances are required (Ho et al., 2016). Broadly speaking, economic and policy analysis finds that financial assurance requirements improve operators' behavior, and the actual amounts required in most jurisdictions may be too low (Davis, 2015; Ho et al., 2016; Boomhower, in press)

Finding 4-3: Financial assurance requirements across states, such as indemnity bonds and fees, are broadly found to improve operator behavior.

States accept various types of financial assurance, including surety bonds, letters of credit, certificates of deposit, cash, escrows or trust accounts, liens, government bonds, or annual fees. California accepts bonds, certificates of deposit (CDs), or cash (it used to accept escrow accounts, but no longer does). Operators may choose between individual and blanket bonds as forms of assurance. Individual bonds cover a single well, while blanket bonds cover a number of wells. The amount of these bonds varies, but generally, most states do not collect sufficient financial assurance to cover the entire costs of decommissioning orphan wells (Louisiana Legislative Auditor, 2014; Ho et al., 2018).

The bond amount required depends upon the characteristics of the well and/or the operator. In terms of physical well characteristics, California determines individual bond amounts by well depth, idle status, and location (onshore or offshore). Well depth is the most common characteristic employed by states to determine bond amount, but not the only one; a few states also differentiate between the type and location of the wells. Like most states, California also differentiates between large and small operators, allowing a range of blanket bonds whose costs depend on an operator's total number of wells in the state. As discussed in Chapter 2, blanket bonds in California range from $200,000 to $3,000,000, depending on the total number of wells operated in the state. California requires a $1,000,000 blanket bond for one or more offshore wells, and also requires a security to cover the full cost of plugging and decommissioning an operator's offshore wells. At present California's current requirements for new or newly-transferred wells are at the upper end of the scale in terms of minimum bonds required. Unlike other states, however, existing wells in California may be grandfathered in under previous bond requirements if operators have not reworked or acquired any wells since the most recent requirements were implemented.[1] Additionally, some wells may have had their bonds released upon completion of the well under old requirements, prior to plugging and decommissioning. This situation contrasts with a universal bond requirement, as implemented by Texas, where all qualifying operators would be required to file the new bond amount at the time of the policy's implementation. Most states, and the Bureau of Land Management, have a minimum blanket bond amount set at $25,000. California also requires idle well fees—or an Idle Well Management Plan—even if an idle well is already covered by a bond.

Finding 4-4: California is now at the upper end of minimum bond amounts currently required, but existing wells in California may be covered by older bonds or no bond at all depending on when they were last drilled, reworked, or acquired, and whether the bond was released prior to plugging. This contrasts with a universal bond requirement, as implemented by Texas, where all qualifying operators would be required to file the new bond amount at the time of implementation.

Financial assurance requirements in most states do not fully cover orphan well-related costs. Wyoming, which has bonding requirements similar to California, spent $11 million plugging orphan wells between 1997-2014, but only $3 million was covered by bonds put up as financial assurance by operators (Joyce & Wirfs-Brock, 2015). Another study found the average and median decommissioning costs exceeded average bond amounts in all 22 states examined (Ho et al., 2016). A separate study of average bond amounts and average costs of well plugging in 13 states found that two states, Texas and Oklahoma, did have average bond amounts which exceeded the average cost of orphan well plugging (Ho et al., 2018). Texas's introduction of a universal bond requirement in the early 2000s changed the composition of the industry, re-allocating production to companies less likely to avoid liability through bankruptcy and improving environmental compliance (Boomhower, in press).

One of the issues in estimating financial assurance requirements is that well plugging costs are variable depending not only on the specific location and characteristics of the well, but also on the price of oil at the time. When oil prices and production are high, there are higher prices for drilling wells, and consequently more competition for the service providers contracted to plug orphan wells. One recent study (Ho et al., 2018) found a $1 per barrel increase in oil price correlated with a 1.6% increase in plugging costs.

California has modified its bonding requirements repeatedly over the past five years (Wolk, 2013; Williams et al., 2016) and increased potential bonding requirements for offshore drilling as recently as September 2018 when SB 1147 (Hertzberg) was signed by the Governor. Some have suggested that an effective way to ensure that states would be

1. PRC § 3204: "An operator who…engages in the drilling, redrilling, deepening, or in any operation permanently altering the casing, of a well, or who acquires a well, shall file with the supervisor an individual indemnity bond for each well so drilled, redrilled, deepened, or permanently altered, or acquired."

able to cover the cost of orphan wells would be to tie bonding requirements to production (Andersen et al., 2009); others indicate that bonding requirements should be a minimum of $250,000 per well (Dutzik et al., 2013). However, these are not approaches states have opted for (Joyce & Wirfs-Brock, 2015). Instead, they all have specific bond amounts, generally linked to well depth, starting in some cases as low as $500 per well.

California law does not require a test of financial capability, but where an operator has a history of violating legal requirements or has outstanding financial liabilities, as of 2018 they may be required to provide a separate life-of-well bond adequate to ensure the full costs of proper plugging and decommissioning of each well.[2]

Compared to other states, California has been somewhat proactive in attempting to modulate its financial assurances to better provide for costs relating to orphan wells. However, its requirements have been insufficient to cover costs. Along with the Division's annual expenditure authority for hazardous or orphan wells and facilities, recently increased to up to $3 million per fiscal year, the State has relied on two funds supported by industry fees to plug priority orphan wells annually: the Acute Orphan Well Account and the continuously appropriated Hazardous and Idle-Deserted Well Abatement Fund (HIDWAF). At the end of fiscal year 2016-17, the combined total in these funds was just over $1.1 million. In cases where costs of plugging wells are higher than normal, such as for offshore wells or wells in highly populated areas, the funds are not sufficient to pay the costs. This lack of funds has occasionally required special appropriations in the State budget.

It should be noted that regions outside the US have adopted different strategies. The Canadian province of Alberta, which had more than 3,200 orphan wells in 2017, generally relies on two policy tools to address potential well plugging costs: an orphan well levy collected from all well operators, and a form of contingent bonding called the Liability Management Regime (LMR; Dachis et al., 2017). The well levy, which is set as a proportion of firms' share of total liabilities, does not differentiate between financially strong and weak producers, and is not reflective of environmental risk. The LMR system does account for the financial strength of producers, and uses a three-year netback to calculate the value of their assets in order to account for fluctuating energy prices, which affect the value of the well. While Alberta's system has been adequate to cover costs in the past, a rising number of operator insolvencies, in combination with lower oil and gas prices, mean the existing system will not remain sustainable unless modifications are made. Further, Canada is confronting major legal questions regarding the order of priority for decommissioning costs in bankruptcy proceedings.

Finding 4-5: In Canada, Alberta collects an orphan well fee from all operators and utilizes contingent bonding based on the financial strength of the operator to pay for orphan wells. However, Alberta is facing an increase in insolvencies in combination with lower

2. CCR, Title 14, § 1722.8.

oil and gas prices and hearing major legal questions regarding the order of priority for decommissioning costs in bankruptcy proceedings.

Idle well management and regulation

When a well's production drops below a certain threshold the decision to continue producing will depend upon oil or gas prices. Operators may choose to stop production on a well that is not performing at an economical rate, keeping it officially active but maintaining it in an idle state rather than decommissioning it. Most states impose a limit on the amount of time a well can remain idle, after which the operator has a choice of restarting production, adopting a status called temporary abandonment (which is also generally limited), or decommissioning the well altogether. Generally, wells that are idle or temporarily abandoned come with stipulations that operators take some steps to limit or mitigate potential environmental impacts. States allow this as an incentive for operators who may reactivate the wells in the future, as it's more expensive to reactivate a fully decommissioned well than one which is simply idle. However, research has shown that the longer a well is idle, the greater the environmental risks, and that there is a low likelihood of returning a well to production (Muehlenbachs, 2017).

California in some respects has been more permissive than most states, with no specific limit on the time a well may remain idle before it must resume production or be decommissioned. Previously, California had a 300-month limit on a state of temporary abandonment, which was significantly longer than most states. Most states (19 out of 22 surveyed by Ho et al. (2016)) imposed a limit of no more than 24 months for idle wells, and (excluding California) an average maximum of 28 months for temporary abandonment; only six other states had default time limits as high as 60 months. All of the states but New Mexico, which regulates the duration of temporarily abandoned well status, allowed for some form of extension. Outside of the U.S., the provinces of Alberta and Saskatchewan also had no time limits for suspended wells (Dachis et al., 2017).

Finding 4-6: In contrast to California, many states imposed a limit on the length of time a well may be idle. However, in practice the impact of these rules tends to be limited by exemptions and extensions.

California was one of only two states (along with Texas) that didn't have explicit notification, approval, and inspection requirements for idle wells. Of the other states surveyed, only four require simple notification; the remaining 16 require some form of approval and/or inspection from the state before a well can be declared idle.

Although aspects of California's idle well regulations may be less stringent than other states, California has taken steps to try and limit the amount of time operators maintain wells in this status by increasing the fees required as in AB 2729 (Williams et al., 2016). This was intended as a financial disincentive to keeping wells idle for longer periods of time, during which time they may be more likely to have negative environmental impacts. As an alternative to fees, operators may file an idle well management plan, which requires the operator to eliminate a specific percentage of their long-term idle wells each year based on how many idle wells they have. In addition, AB 2729 also established requirements for idle well testing, beginning at least two years after a well becomes idle.[3] For idle wells that have been idle for 15 or more years, they will be required to be tested through an engineering analysis to show that they could potentially return to production. As of September 2018, the Division has proposed updated testing and management regulations with a deadline for public comment of September 13, 2018.

Plugging and restoration regulations and procedures

There exists significant variation among state regulations concerning how a well should be properly decommissioned. There are multiple aspects of well decommissioning that regulations may cover, including the types of material used, whether a surface casing plug is required, how or if the casing needs to be removed, and subsurface geography, such as oil- and gas-producing strata, water-bearing strata, and so forth. While pertinent regulations in virtually all states contain some general language about plugging the wells adequately, only some states offer specific requirements as to what kinds of materials and/or methods need to be used, and under what circumstances.

California regulations are more specific than most states in many respects, although the state has gaps in some areas compared to others. Ho et al. (2016) identified 17 regulatory elements which they used to survey 22 states and the BLM; they found California regulations to address 13 of these, placing the state in the bottom tier of the survey group. In terms of the stringency of their regulations overall, California placed ninth and sixteenth respectively in their quantitative and qualitative assessment of these regulations.

However, where California does have regulations in place, they tend to be more specific than many other states. For example, California was one of only three states surveyed with prescriptive requirements for different types of well plugs depending on the location within the well (bottom, middle, or top). Only Colorado and Ohio had similarly specific regulations for all three. California also requires permanent marking of decommissioned wells, a requirement in only half of the states surveyed. Both operators and regulators are required to report idle wells—a situation shared only by Wyoming and BLM lands. California's plugging regulations require plugs to be placed at the surface casing shoe, across oil and gas bearing strata extending 100 feet above the strata, extending from 50 feet below to 50 feet above water-bearing strata, and a 50-foot plug at the surface of the wellbore (NPC, 2011).

Notification, approval, and inspection requirements

California policy is similar to most other states with regard to reporting idle wells, the

3. This testing includes fluid level tests and casing pressure tests, with a follow-up schedule dependent upon the psi of the initial pressure tests.

plugging of wells, and decommissioning. California requires both regulators and operators to file reports detailing idle wells. It requires inspection pre- and post-plugging of the wells, but not post restoration of an abandoned well. In this, it is comparable to most other states reporting. Of those states which have evaluated their own abandoned well policies, most have concluded that they have not sufficiently ensured that operators comply with regulations (Louisiana Legislative Auditor, 2014; Joyce & Wirfs-Brock, 2015). California is no different in this regard. Outside the US, some Canadian provinces have a more rigorous and transparent system for ensuring required inspections and compliance. The Alberta Energy Regulator (AER) requires inspections at each stage and publishes regular reports on compliance violations and punitive actions taken.[4]

Most analyses which examine orphan well plugging and decommissioning costs warn that the price of plugging is likely to continue rising, if for no other reason than that the strongest single predictor of plugging cost appears to be the depth of the well, and well depths continue to rise. These rising costs, along with a potential need for older wells to be remediated in the future, suggests any financial assurance model based on static costs may require periodic revision. California's continual revisions to the regulations governing financial assurances indicate the state is more proactive than most in recognizing and attempting to manage the issue of orphan well closures. However, like most states, the state has (until recently) not had an enforcement infrastructure or adequate policy framework in place to effectively gauge the true scope of its potential and actual orphan well issues. California is implementing changes, including the recently updated idle wells program and the establishment of an Office of Enforcement, which should provide both more information about the scope of the issues and more effectively enforce regulations going forward.

Finding 4-7: As the total number of wells, cost to plug each well, and number of older wells requiring remediation is likely to increase for the foreseeable future, it is likely that any financial assurance model based on a static cost level will require periodic revision.

Conclusion 4-1: Historical experience and policy analysis in oil-producing regions throughout North America demonstrate the urgency and importance of orphan and idle well regulation. Most studies agree that higher bond requirements for operators will more fully internalize orphan well liabilities. Laws governing the priority of decommissioning costs are also important in determining potential costs to governments when operators become insolvent.

4. http://www1.aer.ca/compliancedashboard/enforcement.html

Conclusion

Significant financial concerns exist about decommissioning inactive wells—that is, permanently plugging the wells and reclaiming the surrounding well sites. All producing states and regions face challenges with managing and decommissioning what are known as orphan wells, those without a responsible owner. Since drilling began in the United States in the 1850's, over 2.5 million wells have ceased production. As of 2007 at least 149,000 of these are known to be orphan wells, though the actual number of orphan wells requiring potential remediation is almost certainly significantly higher.

Even the most productive well has a certain useful lifetime. Plugging the well properly at the end of this lifetime can be an expensive procedure whose cost can fluctuate significantly depending on numerous factors, including the well's depth, location, and the price of oil. Wells often pass through the hands of multiple operators through their operational lifetime; frequently operators controlling wells near the end of their lifetime are smaller companies more vulnerable to bankruptcy or dissolution, resulting in orphan wells which the state must then step in and plug itself.

As the overall number of wells has increased, so too has the number of orphan wells, and concomitantly the various states' financial burden. In recent years, state legislatures and oil and gas regulators have increased funding for well cleanup by appropriating more money and increasing bonding requirements. They also have tried to make it harder for companies to walk away from their wells, such as by intervening earlier to prod companies to reactivate or plug wells that are sitting idle.

California, like many states, has devoted increasing effort in recent years to designing a regulatory framework which seeks to both reduce the number of operators orphaning wells in the first place and secure financial assurances adequate to pay for plugging the well when necessary. Currently, California requires well operators to obtain individual or blanket bonds prior to drilling, reworking, or acquiring a well or wells. The amount of the bond required depends on the depth of the well, the number of wells owned by the operator, and the location of the well; bond amounts for most wells range from $25,000 for a single well to $3,000,000 for a blanket bond covering multiple wells. Offshore wells, which comprise only 2% of wells in California but are much more expensive to plug, require an additional bond. The State also collects fees on wells that are kept idle by operators. While the effective amount of bond funds varies across wells, an analysis of the Division data shows that bond funds are typically far below likely plugging and remediation costs.

The Division is currently in the process of implementing updates to their idle well fee and management requirements, including new idle well testing and reporting requirements. These requirements are intended to improve management of this population of wells and protect the State and public against both environmental and financial costs. Future evaluation efforts will gauge the success of these new regulations. For now, at least, there remain significant financial concerns about the existing inventory of orphan wells and the stock of inactive wells that could be orphaned.

While the State currently maintains a comprehensive list of idle (non-producing) wells, the share of these wells that are orphan wells is unknown. A coarse analysis of data provided by the Division on 228,648 wells suggests there are 2,565 “likely” orphan wells belonging to operators with no reported California activity in five years, and an additional 2,975 wells at high risk of becoming orphaned, which have had no production over the past five years and are owned by smaller operators with primarily low-producing wells (which other research suggests are more likely to orphan wells). After subtracting out bond funds associated with the wells, the potential net liability to the State for wells in these categories is about $500 million. There are an additional 69,425 idle and marginal wells and 31,722 higher-producing wells. The eventual cost to plug and abandon all existing wells in California is found to be about $9.1 billion. The share of this long-run cost that will be borne by the State (as opposed to operators) will depend on policy, market outcomes, and other factors.

It is too soon to tell whether California’s current bond requirements and idle well fee collection will prove adequate to cover the cost of orphan well plugging in upcoming years. One of the most significant challenges facing California, along with every other state, is inadequate data. It is not possible to adequately assess the scope of the problem when information about the status of idle wells is incomplete and gathered intermittently. For one thing, existing wells in California may be grandfathered in under previous bond requirements if operators have not reworked or acquired any wells since the most recent requirements were implemented. Also, some wells may have had their bonds released upon well completion, prior to plugging and decommissioning, under old requirements. This contrasts with the approach taken in other states such as Texas, which has implemented a universal bond requirement applicable to all wells, and which was one of the few whose available bond funds have been sufficient to offset the cost of plugging orphan wells in recent years.

As noted earlier, California’s situation is not unique. Analyses have found that most states struggle to meet the costs of plugging orphan wells and typically decommission only a fraction of known orphan wells each year. Like California, the states surveyed have updated their regulations in recent years but these efforts have generally proven insufficient to meet expenses so far.

The estimates we provide in this paper are preliminary and based on coarse sorting criteria using available data. As the Division implements the updated idle well regulations, with mandatory annual reporting requirements, California will gain a more comprehensive and accurate list of remaining hazardous and orphan wells, along with a better sense of responsible operators based on compliance with the updated requirements.

Historical experience and policy analysis in oil-producing regions throughout North

America demonstrate the urgency and importance of orphan and idle well regulation. Most studies agree that higher bond requirements for operators will more fully mitigate the State's orphan well liabilities. Laws governing the priority of decommissioning costs are also important in determining potential costs to governments when operators become insolvent.

California's recent regulatory changes are encouraging. However, it is essential that California continue to evaluate the status of its potential financial liability in upcoming years. A more detailed analysis will be necessary once the State's new idle well reporting requirements are in place, in order to ascertain the State's actual and potential liability more accurately.

The State must also be prepared to accept the fact that, due to the rising number of wells overall, cost to plug each well, and number of older wells requiring remediation, it is likely that any financial assurance model based on a static cost level will require periodic revision. Hopefully, the new information collected and subsequent analyses will help ensure that the State is in a better position to understand its liability, and that such revisions may be implemented in a timely manner.

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Glossary

Abandon – to properly plug and/or decommission a well

Blanket bond – a single bond or bond amount to cover one or more wells

Decommission – to remove all of the components of a production facility and restore the site where it is located

Idle well – a well that has not, for 24 consecutive months, produced oil or natural gas, produced water to be used in production stimulation, or been used for enhanced oil recovery, reservoir pressure management, or injection

Indemnity bond – also known as a surety bond, an agreement between three groups, the principal conducting the work (operator), the obligee to whom money is owed if obligations are not met (the State), and a surety bond company (surety)

Insolvent – unable to pay one's debts or when liabilities are greater than assets held

Long-term idle well – a well that has been an idle well for 8 or more years

Marginal well – a well that produces fewer than 10 barrel-of-oil equivalents per day

Orphan well – a well for which there is no known responsible operator or no financially viable operator capable of plugging and decommissioning the wells

Plug – to properly isolate, using cement and cement plugs and other required materials, the oil or gas containing components of a well from their surroundings, including from water reservoirs

Appendix A

Additional Background

A1. Select history of bonding requirements in California

Table 9: Select history of bonding requirements in California

Bill, Chapter	Year Bill	Individual PRC § 3204	Blanket Bonds PRC § 3205	Offshore Bonds PRC § 3205.1	Cash Bonds PRC § 3205(3)(b)	Idle Well Bonds and Fees PRC § 3206	Idle Well Mgmt. Plan PRC § 3206	Idle Testing/Reporting PRC § 3206.1
SB 724	**2017** SB 724							
AB 2729	**2016** AB 2729		Adds $2,000,000 > 500 and ≤ 10k $3,000,000 > 10k wells Repeals $2M all-inclusive bond		Removes explicit cash bond language in PRC, referencs Code of Civil Procedure bonding section	Fees for idles, even if bonded: 3 to under 8 yrs: $150 each 8 to under 15 yrs: $300 each 15 to under 20 yrs: $750 each 20 or longer: $1,500 each OR Idle Well Plan Repealed escrow option	≤ 250: 4% reduct.* 251 to 1,250: 5% reduct.* ≥ 1,250: 6% reduct.* *not less than one well/yr	Est. testing; 15 years+ tested that could return to production, not req. until at least 2 years after idle unless within 1/2 mile to underground drinking water. Reporting reqs for idle/orphan wells
SB 665	**2013** SB 665	$25,000 < 10k ft $40,000 ≥ 10k ft	When altering 20 or more wells: $200,000 ≤ 50 in state + Idle fees/bonds $400,000 > 50 in state + Idle fees/bonds $2,000,000 All, covers idle fees/bonds	$1,000,000				
AB 2581	**2000** AB 2581	Revised operator liability for reabandonment; expanded supervisor authority						
SB 1763	**1998** SB 1763	$15,000 < 5k ft $20,000 — $30,000 > 10k ft	When altering 1 or more wells: $100,000 if 50 or fewer in state $250,000 if more than 50 in state $1,000,000 All wells and idle fees extra		Blanket: If prior to 1/1/1999 increased minimum $30k per yr until matching	Less than 10 yrs: $100 10 to under 15 yrs: $250 15 yrs or longer: $500 OR $5,000 escrow per ($500 per year for 10 yrs) OR $5,000 indemnity per OR Management Plan AND Acquired idles need bonds	≤ 20 idle wells: 1 per yr. 21 to 50: 2 per yr. 51-100: 5 per yr. 101-250: 10 per yr. > 250 wells: 4% per yr.	
SB 2007	**1996** SB 2007	Fallback to transfers on or after 1/1/1998						
AB 1504 Ch. 1179	**1993** AB 1504			Allowed full cost security for plugging all offshores				
SB 2693	**1990** SB 2693					$5,000 bond/well or $100,000 blanket or $100/well annually		
Ch. 112	**1977** Ch. 112	$10,000 < 5k ft $15,000 -- $25,000 > 10k ft	When altering 1 or more wells: $100,000	$250,000	$12,000 $18,000 $30,000 Blanket: $120,000 Offshore: $300,000			
Ch. 794	**1976** Ch. 794	$25, 000 / well	When altering 1 or more wells: $250,000		$30,000 Blanket: $300,000			
Ch. 898	**1972** Ch. 898	Need bond to plug						
Ch. 1670	**1955** Ch. 1670		When altering 1 or more wells: $25,000					
Ch. 93	**1939** Ch. 93	$5,000 / well	When altering 5 or more wells: $25,000 (Covers all wells)					
Ch. 718	**1915** Ch. 718	Division established						

Appendix B

Additional Results

B1. Alternative rules for identifying orphan wells

Our analysis in Chapter 3 proposes a rough screen for categorizing wells according to their risk of becoming orphan wells. This section explores how the results of that exercise vary if we change the assumptions used to classify wells.

Figure 8 shows the number of "likely orphan wells" and "wells at high risk of becoming orphan wells" under a range of assumptions. The 40 markers in this figure represent well counts under different classification rules. The green circles show how the number of "likely orphan wells" varies with the minimum required period of inactivity at all of an operator's wells. Varying this period between one and ten years has a small effect on the implied count of likely orphan wells.

The three other marker types explore the number of wells "at high risk of becoming orphan wells." Recall that these are currently inactive wells whose operators are active but potentially vulnerable to insolvency or otherwise at risk of not plugging and abandoning wells. Each symbol type corresponds to a different rule for identifying potentially vulnerable operators. The various points for each symbol type show the number of wells that have been idle for the number of months on the horizontal axis, and whose operators are vulnerable under the given vulnerability rule. In our main analysis, we define operators as vulnerable if they have fewer than 1,000 wells and their average production is less than five BOE per well per day. That rule is shown with the orange triangles. The purple squares and pink crosses vary the number of wells threshold up and down, while maintaining the five BOE per well per day threshold.

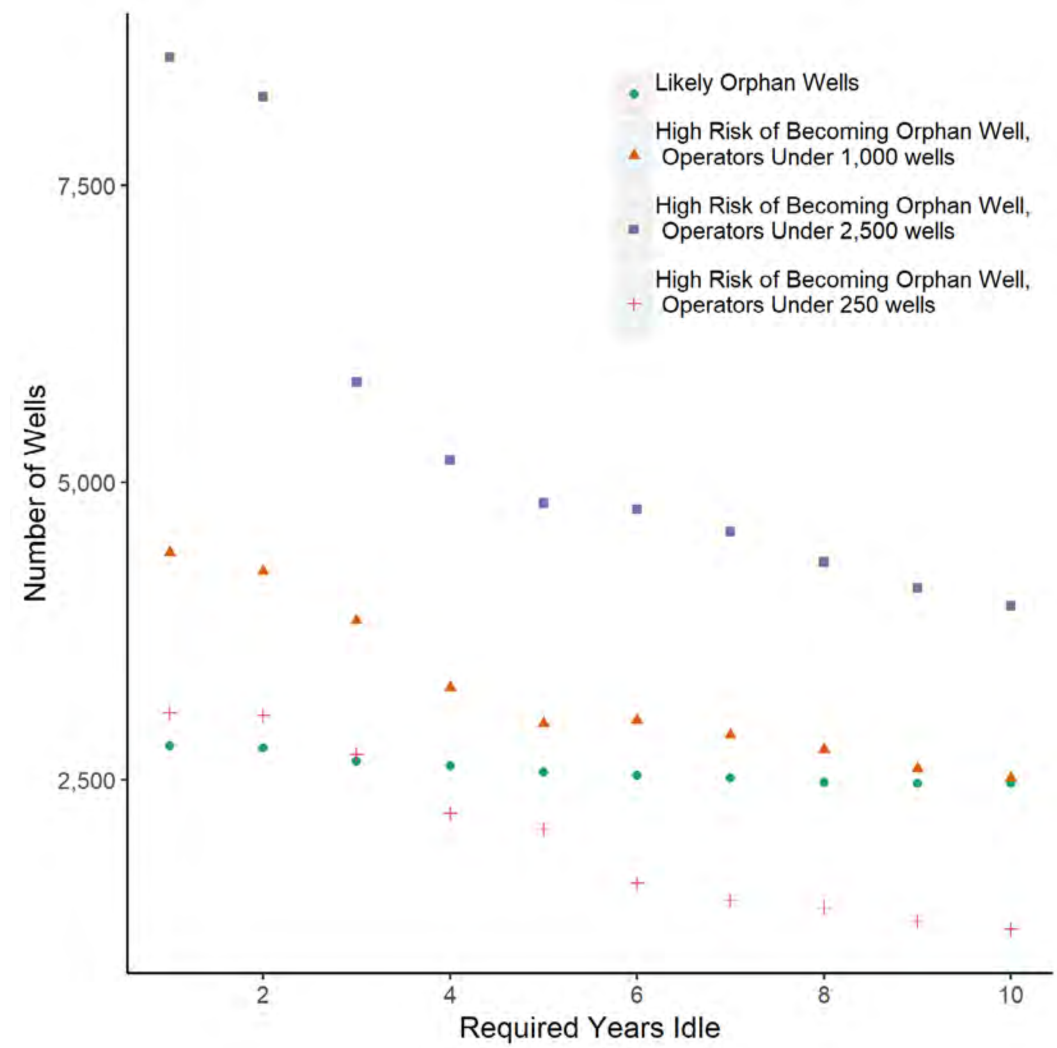

Figure 8. Alternative assumptions for orphan well risk assessment. Each marker shows a count of wells in a given category, using various assumptions about orphan well risk. The marker styles correspond to four different sets of related assumptions. See text for details.

B2. Probability of restarting production

A common challenge in analyzing and regulating idle wells is understanding whether wells are kept idle because the operator has a reasonable expectation of eventually resuming production, or simply to defer decommissioning costs. If it is the former, plugging the well creates additional economic costs in terms of foregone option value. Plugging the well today increases the cost of resuming production in the future if prices or technology improve. It is impossible to know any individual operator's expectations about future production, but we can use historical data on idle wells to understand the average likelihood of returning to production after a given interval with no production. The most sophisticated existing economic research on this question is Muehlenbachs (2015), which considers idle oil and gas wells in Alberta, Canada. That research concludes most long-term idle wells are unlikely to return to production even with large increases in output prices or improvements in production technology. Given appropriate data, a similar study could be carried out for California. This appendix describes a first pass at this type of analysis for California using the data that were readily available and describes what would be required to study this question in more detail.

One relatively straightforward statistic to calculate is the share of wells kept idle in the past that have eventually returned to production. Specifically, conditional on reaching a given length of time without producing (and without being plugged), what is the probability that an idle well will eventually return to production? Figure 9 reports the results of such a calculation. For wells with a given period idle during 1977—2008, the figure shows the probability that the well resumed production prior to the end of 2017. Intuitively, the probability of resuming production decreases with the length of time since the well last produced. After one year idle, there is an almost 50% chance of resuming production on average. Once a well has been idle for 25 years, that probability falls to about 12%. This retrospective analysis represents a historical average across all wells and should be interpreted with caution. There may be substantial heterogeneity in restart probabilities across different fields, well types and operators. A detailed study of option value associated with idle wells in California would need to consider these factors. In addition, it would be important to consider a range of future price and technology projections.

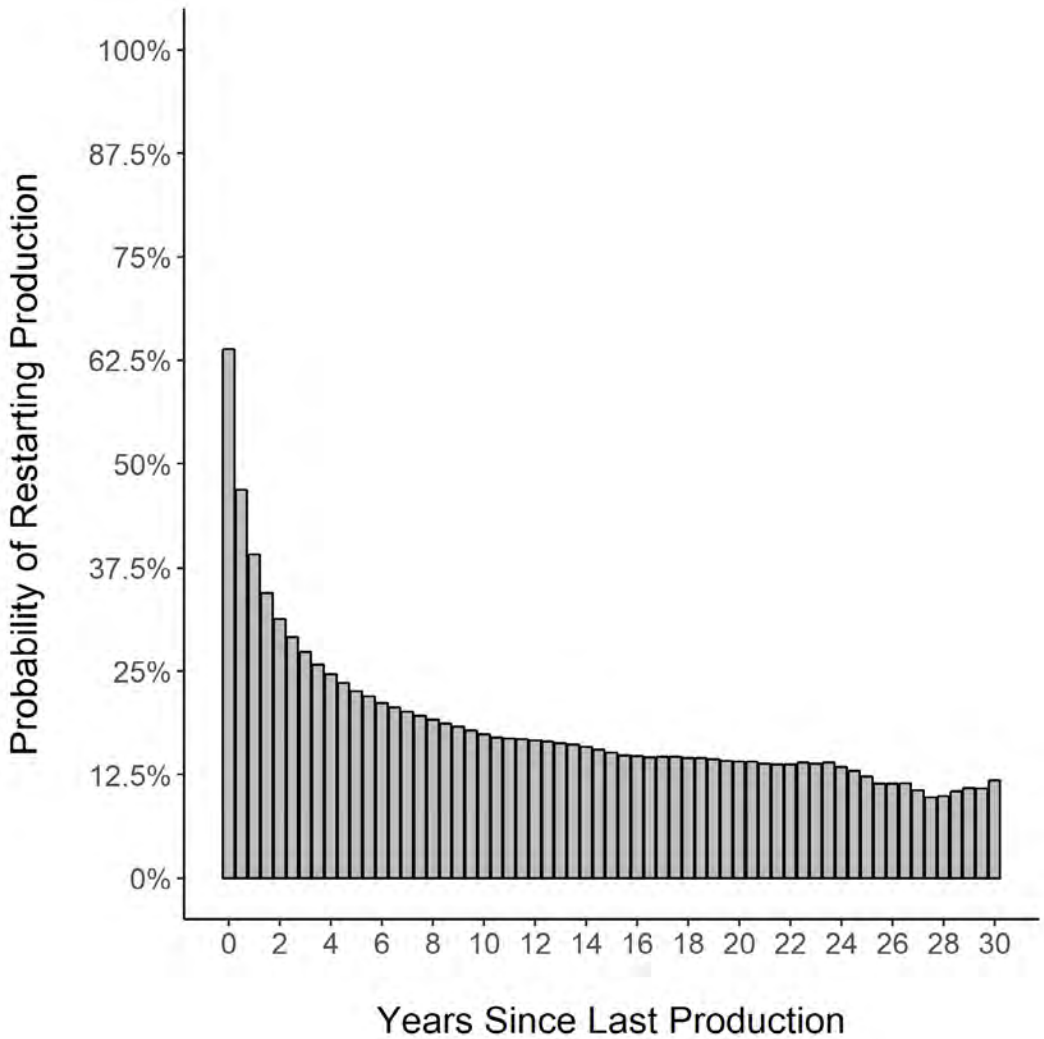

Figure 9. Historical probability of restarting production after a given idle interval. This figure shows the probability a well will restart production following a given period idle. To allow at least 10 years for production to resume, this figure is limited to 1977–2008. Wells that produced oil or natural gas in at least one month before the end of 2017 are considered to have resumed production. See text for details.

B3. Relationship between plugging costs and imputed well depth

Data on well depth were not available for any of the 86 wells with historical plugging costs (Table 7). As an attempt to impute well depth, the average depth of other wells in the field containing the well was used as a proxy. Figure 10 shows the relationship between plugging costs and the imputed depth measure. Instead of indicating no relationship between cost and well depth, this figure likely serves as evidence that imputed well depth is a poor proxy for actual well depth.

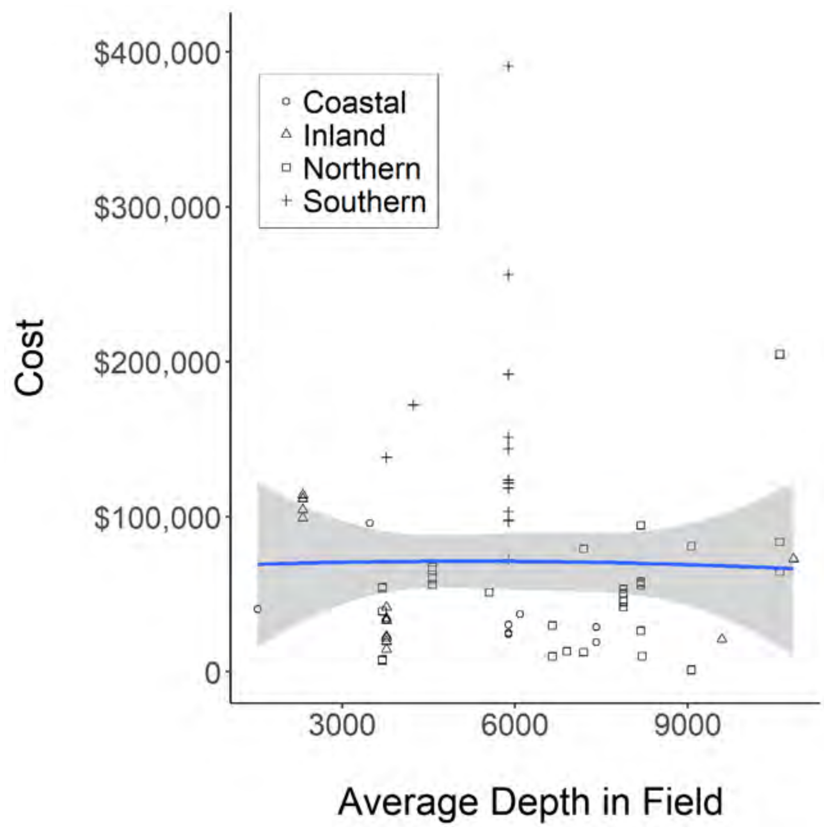

Figure 10. Relationship between plugging costs and imputed well depth. Data on well depth were not available for any of the 86 wells with historical plugging costs. This figure likely serves as evidence that imputing well depth using the average depth of other wells in the field containing the well is a poor proxy for actual well depth.

Appendix C

Construction of the Dataset

This section describes how the raw datasets provided by the Division were combined to create the final analysis dataset.

Monthly production and injection data

The raw monthly production data consist of 43,875,893 monthly observations for 176,823 wells. We drop a small number of observations prior to January 1, 1977, since reporting for most wells begins in 1977. We also drop observations after December 31, 2017, since the completeness of the data for 2018 appears to vary across wells. Missing values are reported for some monthly production observations. We replace these values with zeros if they occur after the first observed non-zero production for a given well. We drop these observations if the month is earlier than the first month of non-zero production for the well. There are also gaps in the production records for some wells. We fill in zero production in any missing months after the first reported production from each well. We further incorporate data on monthly injection volumes from the Division's monthly well injection dataset to identify wells currently being used for injection.

Well-level characteristics files

The well-level characteristics data include 270,524 records. We exclude 29,783 duplicate records with identical API numbers and wellbore codes. We further exclude 12,093 wells with a status of "Cancelled", which indicates that these wells were permitted but never actually drilled.

We successfully merge 94% of active and idle wells and 61% of plugged wells to the production dataset. In our analysis of active and idle wells, for the remaining 6% of wells that do not appear in the production dataset, we assume that there was no reported production during the period of the data, and so assign these wells zero production in every month.[1]

Plugging cost data

As described in the main text, the Division provided various records of plugging costs for wells that have been plugged at state expense. By combining these records, we were able to

1. Hand checking of a subsample of the unmerged records with the Division's online well search tool supports our assumption that the unmerged records represent very old wells with no recent production.

identify 86 unique wells where costs were reported at the individual well level and an API number was included in the record.

Well depth data

The Division provided information on well depth for a subsample of 27,530 wells. We generate an interpolated depth for as many wells as possible by using these observed depths to calculate an average depth in field for every oil field where we observe at least one well depth.

Appendix D

CCST Study Team

Full curricula vitae for the Study Team members are available upon request. Please contact California Council on Science and Technology (916) 492-0996.

Study Team Members:

- **Judson Boomhower**, PhD, University of California, San Diego
  Lead Author

- **Terence Thorn**, JKM Consulting
  Steering Committee (Chair)

- **Mikel Shybut**, PhD, California Council on Science and Technology
  Author and Project Manager

- **M. Daniel DeCillis, PhD**, California Council on Science and Technology
  Author

- S**arah E. Brady, PhD**, Interim Deputy Director, California Council on Science and Technology
  Project Director

- **Amber J. Mace, PhD**, Interim Executive Director, California Council on Science and Technology

Judson Boomhower, Ph.D.

Lead Author
Assistant Professor, Department of Economics, UC San Diego

Judson Boomhower is an applied microeconomist who studies environmental and energy economics and policy. His research covers a range of topics and industries including oil and gas extraction, electricity markets, energy efficiency, and the economics of climate change. He received a PhD in Agricultural and Resource Economics from the University of California, Berkeley. He earned his bachelor's and master's degrees from Stanford.

Terence Thorn

Steering Committee Chair
President, JKM Energy and Environmental Consulting

Terence (Terry) Thorn is a 43-year veteran of the domestic and international natural gas industry and has held a wide variety of senior positions beginning his career as Chairman of Mojave Pipeline Company and President and CEO of Transwestern Pipeline Company. He has worked as an international project developer throughout the world.

As a Chief Environmental Officer, Terry supported Greenfield projects in 14 countries to minimize their environmental impact. He wrote and had adopted company wide Environmental Health and Safety Management Standards and implemented the first environmental management plan for pipeline and power plant construction. In attendance at COP 1 and 2, Terry has remained involved in the climate change discussions where he is focusing on international policies and best practices to control methane emissions.

Residing in Houston, Terry is President of JKM Energy and Environmental Consulting and specializes in project development and management, environmental risk assessment and mitigation, business and policy development, and market analysis. He has done considerable work in the areas of pipeline integrity management systems, management systems auditing, safety and reliability and the reduction of methane emissions from natural gas facilities.

He also serves as Senior Advisor to the President of the International Gas Union where he helps drive the technical, policy and analytical work product for the 13 Committees and Task Forces with their 1000 members from 91 countries. He also serves on the Advisory Boards for the North American Standards Board where he co-chaired the gas electric harmonization task force, and the University of Texas' Bureau of Economic Geology's Center for Energy Economics. Terry is also on the Board of Air Alliance Houston. He served on the CCST California Council on Science and Technology steering committee for the report that provided the state with an up-date and independent technical assessment of the thirteen natural gas storage fields in California. Currently he is on the CCST team that will estimate the liability and costs to the state of plugging and abandoning oil and gas wells and decommissioning their attendant facilities.

Terry has published numerous articles on energy, risk management and corporate governance and was author of the International Energy Agency's 2007 North American Gas Market Review. As advisor to European gas companies and regulators he co-authored The Natural Gas Transmission Business -a Comparison Between the Interstate US-American and European Situations, Environmental Issues Surrounding Shale Gas Production, The U.S. Experience, A Primer. As a participant in the National Petroleum Council Study Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources (September 2011), Terry wrote the section on electric gas harmonization, co-authored the chapter on electric generation, and advised on the residential commercial chapter. Most recently he has completed market research projects on electricity markets, gas markets including modeling the US gas markets 2015-2050. Gas Shale Environmental Issues and Challenges was just published by Curtin University in 2015. His most recent papers are "The Bridge to Nowhere: Gas in An All Electric World," "The Paradigms of Reducing Energy Poverty" and "Making Fossils Fuels Great Again: Initial Observations About Trump's Energy Policy."

Mikel Shybut, Ph.D.

Author and Project Manager
Program Associate, California Council on Science and Technology

Mikel Shybut is a CCST Program Associate. Previously he was a CCST Science and Technology Policy Fellow appointed to the California State Senate on the Transportation and Housing Committee, which analyzes legislation covering policy areas from essential infrastructure needs to autonomous vehicles and affordable housing.

Shybut received his PhD in Plant Biology from UC Berkeley, where he studied the molecular mechanisms of cassava bacterial blight, a disease of agricultural significance in the tropics. Shybut completed his BA in Biological Chemistry and in Russian at Grinnell College in Iowa.

M. Daniel DeCillis, Ph.D.

Author

Senior Research Associate, California Council on Science and Technology

M. Daniel DeCillis is Senior Research Associate & Director of Web Operations at the California Council on Science and Technology, where he has worked since 2001. He has been principal project writer on studies including the Overview of California State-Funded R&D, 2004-2007 (2008), Critical Path Analysis of California's Science and Mathematics Teacher Preparation System (2007), An Industry Perspective of the Professional Science Master's Degree in California (2005), Opportunities for Collaboration in High-tech Research and Teacher Professional Development (2004), the Critical Path Analysis of California's Science and Technology Education System (2002), and The Preparation of Elementary School Teachers to Teach Science in California (2010); he has also contributed substantially to CCST projects on nanotechnology, energy, and intellectual property. In addition he designed and edited the Workforce Investment Board Online Toolkit (2008), a major component of CCST's contributions to the California Innovation Corridor project. In 2011, he edited and reviewed Imagining the Future: Digitally Enhanced Education in California and components of California's Energy Future. In 2012, he completed the California Climate Change Research Database website. He was part of the team that produced the 2014 report Achieving a Sustainable California Water Future through Innovations in Science and Technology and a co-author on Promoting Engagement of the California Community Colleges with the Maker Movement (2016) and The Maker Movement and K-12 Education (2017).

DeCillis has presented CCST's work on a variety of projects in numerous venues (including the Legislature and the National Academies) both in California and abroad. Since 2002, he has served as primary writer and editor for CCST's Annual Report and newsletter; he is also responsible for design and management of the CCST website. From 2001- 2004 he served as the Managing Editor for the Journal of Robotic Systems. Prior to this, he worked as a paleographer and French instructor; he holds an M.A. and a Ph.D. in Romance Studies from Duke University and a B.A. with High Honors in French and Latin from Oberlin College.

Sarah E. Brady, Ph.D.

Project Director
Interim Deputy Director, California Council on Science and Technology

Sarah Brady, Ph.D. is the Interim Deputy Director for CCST. In addition to managing large-scale commissioned projects requested by the Legislature and state agencies, Sarah leads outreach efforts to connect CCST's network of experts with state decision makers.

Prior to joining CCST, Sarah served as Legislative Director in Assemblywoman Susan Bonilla's office where she was hired after her placement as a CCST Science and Technology Policy Fellow in 2014. During her time with Assemblywoman Bonilla, Sarah initiated policy work to retain women in STEM careers by preventing pregnancy discrimination in graduate programs. As a result of legislation that she conceptualized and staffed through the process, the law now requires all California colleges to establish a family leave policy for their graduate students. Sarah also spearheaded legislation to increase the use of biomethane, reduce the cost of college textbooks, and improve access to computer science education. In addition, she conducted bill analysis and provided vote recommendations to Assemblywoman Bonilla on all bills related to utilities and commerce, energy, water, natural resources, and environmental toxicity.

Sarah earned Bachelor's degrees in Chemistry and French from North Central College and a Doctorate in Chemistry at the University of Oregon researching the degradation of plastics. She was also a GK-12 Fellow and an NSF-IGERT Fellow where she worked at the Hong Kong Baptist University. In her free time, Sarah likes to watch the Green Bay Packers, brew beer, camp, and is the Co-Chair for the CCST Science Fellows Alumni Group.

Amber J. Mace, Ph.D.

Interim Executive Director, California Council on Science and Technology

Amber Mace, Ph.D. is the Interim Executive Director of the California Council on Science and Technology (CCST) and is a Policy Fellow with the UC Davis Policy Institute for Energy, Environment and the Economy. Mace devotes her time to building new and revitalizing existing programs and organizations that are dedicated to increasing the impact and value of science-informed decision-making. Prior to this, Mace served as the Associate Director of the UC Davis Policy Institute for Energy, Environment and the Economy. She also served as the Executive Director of the California Ocean Protection Council (OPC) and Assistant Secretary for Coastal Matters at the California Natural Resources Agency. In this role she applied her background in ocean policy and marine ecology and collaborative leadership skills to guide the state in developing policies that promote the sustainable use of California's ocean ecosystem. Prior to that, she served in the dual roles of science advisor to the OPC and executive director of the California Ocean Science Trust, a non-profit whose mission is to provide objective, high-quality science to decision makers.

She learned firsthand about the challenges of public policy-making at the federal level as a Knauss Fellow in the U.S. Senate Commerce, Science and Transportation Committee, and at the state level as a California Sea Grant state fellow at the California Natural Resources Agency. Amber was recognized as a Coastal Hero by Sunset magazine in 2011 and her California coastal research experience includes piloting a submersible with the Sustainable Seas Expedition. She earned a Bachelor of Arts in geography from UC Berkeley and a doctorate in ecology from UC Davis and the Bodega Marine Laboratory.

Appendix E

Expert Oversight and Review

Oversight Committee:

- **Richard C. Flagan**, California Institute of Technology, CCST Board Member
- **Samuel J. Traina**, University of California, Merced, CCST Board Member
- **Robert F. Sawyer**, University of California, Berkeley, External Member

Report Monitor:

- **Robert F. Sawyer**, University of California, Berkeley

Expert Reviewers:

- **Scott Anderson**, Environmental Defense Fund
- **Dan Arthur**, ALL Consulting, LLC
- **Peter Maniloff**, Colorado School of Mines
- **James McCall**, National Renewable Energy Laboratory
- **Lucija Muehlenbachs**, University of Calgary
- **Samuel J. Traina**, University of California, Merced

Appendix F

CCST Study Process

California Council on Science and Technology (CCST) studies are viewed as valuable and credible because of the organization's reputation for providing independent, objective, and nonpartisan advice with high standards of scientific and technical quality. Checks and balances are applied at every step in the study process to protect the integrity of the studies and to maintain public confidence in them.

Study Process Overview—Ensuring Independent, Objective Advice

For 30 years, CCST has been advising California on issues of science and technology by leveraging exceptional talent and expertise.

CCST enlists the state's foremost scientists, engineers, health professionals, and other experts to address the scientific and technical aspects of society's most pressing problems.

CCST studies are funded by state agencies, foundations and other private sponsors. CCST provides independent advice; external sponsors have no control over the conduct of a study once the statement of task and budget are finalized. Authors and the Steering Committee gather information from many sources in public and private meetings, but they carry out their deliberations in private in order to avoid political, special interest, and sponsor influence.

Stage 1: Defining the Study

Before the author(s) and Steering Committee selection process begins, CCST staff, Board Members, Council Members and other relevant experts work with the study sponsors to determine the specific set of questions to be addressed by the study in a formal "statement of task," as well as the duration and cost of the study. The statement of task defines and bounds the scope of the study, and it serves as the basis for determining the expertise and the balance of perspectives needed for the study authors, Steering Committee members, and peer reviewers.

The statement of task, work plan, and budget must be approved by CCST's Project Director in consultation with CCST leadership. This review sometimes results in changes to the proposed task and work plan. On occasion, it results in turning down studies that CCST believes are inappropriately framed or not within its purview.

Stage 2: Study Author(s) and Steering Committee (SC) Selection and Approval

Selection of appropriate authors and SC members, individually and collectively, is essential for the success of a study. All authors and SC members serve as individual experts, not as representatives of organizations or interest groups. The size of the SC depends on the size and scope of the study.[1] Each expert is expected to contribute to the project on the basis of his or her own expertise and good judgment. Each provisional SC member and author complete a COI form and submit current resumes. CCST staff send all of this information to outside counsel for a thorough COI review and then organize all results and recommendations from the outside counsel. CCST organizes an in-person meeting for the provisional SC and lead authors to discuss the balance of the committee and evaluate each person for any potential COIs based on the outside counsel feedback. Any issues raised in this discussion are investigated and addressed. CCST sends the list and COI information of the provisional SC and lead authors, including any recommendations or concerns from the in-person meeting, to the Oversight Committee (created by the Board and made up of two CCST Board Members and an outside expert) for final approval. While the lead authors attend the meeting for the discussion of their own potential COIs they do not contribute to the discussion of the provisional SC Member's COIs. Members of a SC and the lead author(s) are anonymous until this process is completed. The lead author(s) maintain continued communication with the SC as the study progresses through frequent updates and background meetings.

Careful steps are taken to convene SCs that meet the following criteria:

An appropriate range of expertise for the task. The SC must include experts with the specific expertise and experience needed to address the study's statement of task. A major strength of CCST is the ability to bring together recognized experts from diverse disciplines and backgrounds who might not otherwise collaborate. These diverse groups are encouraged to conceive new ways of thinking about a problem. The size of the SC depends on the size and scope of the study.

A balance of perspectives. Having the right expertise is not sufficient for success. It is also essential to evaluate the overall composition of the SC in terms of different experiences and perspectives. The goal is to ensure that the relevant points of view are, in CCST and the Oversight Committee's judgment, reasonably balanced so that the SC can carry out its charge objectively and credibly.

Screened for conflicts of interest. All provisional SC members are screened in

1. Due to the short duration of this study, the study had only a Steering Committee Chair. Authors drafted findings and conclusions and the lead author drafted recommendations in coordination and with final approval from the Steering Committee Chair.

writing and in a confidential group discussion about possible conflicts of interest. For this purpose, a "conflict of interest" means any financial or other interest which conflicts with the service of the individual because it could significantly impair the individual's objectivity or could create an unfair competitive advantage for any person or organization. The term "conflict of interest" means something more than individual bias. There must be an interest, ordinarily financial, that could influence the work of the SC or that could be directly affected by the work of the SC. Except for those rare situations in which CCST and the Board appointed Oversight Committee determine that a conflict of interest is unavoidable and promptly and publicly disclose the conflict of interest, no individual can be appointed to serve (or continue to serve) on a SC used in the development of studies if the individual has a conflict of interest that is relevant to the functions to be performed.

Point of View is different from Conflict of Interest. A point of view or bias is not necessarily a conflict of interest. SC members are expected to have points of view, and CCST attempts to balance these points of view in a way deemed appropriate for the task. SC members are asked to consider respectfully the viewpoints of other members, to reflect their own views rather than be a representative of any organization, and to base their scientific findings and conclusions on the evidence. Each SC member has the right to issue a dissenting opinion to the study if he or she disagrees with the consensus of the other members.

Other considerations. Membership in CCST are taken into account in SC selection. The inclusion of women, minorities, and young professionals are additional considerations.

Specific steps in the SC selection and approval process are as follows:

CCST staff solicit an extensive number of suggestions for potential SC members from a wide range of sources, then recommend a slate of nominees. Nominees are reviewed, as a provisional SC, at several levels within CCST. Prior to final approval, the provisional SC members complete background information and conflict-of-interest disclosure forms. The SC balance and conflict-of-interest discussion is held at the first SC meeting. Any conflicts of interest or issues of SC balance and expertise are investigated; changes to the SC are proposed and finalized. Finally, the provisional SC is presented to the Oversight Committee for formal approval. SC members continue to be screened for conflict of interest throughout the life of the committee.

CCST uses a similar approach as described above for SC development to identify study authors who have the appropriate expertise and availability to conduct the work necessary to complete the study. In addition to the SC, all authors, peer reviewers, and CCST staff are screened for COI.

Stage 3: Author and Steering Committee Meetings, Information Gathering,

Deliberations, and Drafting the Study

Authors and the Steering Committee typically gather information through:

1. meetings;
2. submission of information by outside parties;
3. reviews of the scientific literature; and
4. investigations by the study authors and/or SC members and CCST staff.

In all cases, efforts are made to solicit input from individuals who have been directly involved in, or who have special knowledge of, the problem under consideration.

For larger reports, lead authors may request additional authors to ensure the appropriate expertise is included. Every author must be approved by the SC and CCST staff. Some of the additional authors may become section leads. The lead author reviews and approves the work of all other chapter authors, including section leads.

During the course of a report, authors' duties may shift which may change the lead author or section lead designations. Any such changes must be made in conjunction with CCST staff and the SC. If the reorganization of author responsibilities or the addition of a new author raises conflict of interest concerns, they are presented to and resolved by the Oversight Committee.

The authors shall draft the study and the SC shall draft the Executive Summary which includes findings, conclusions, and recommendations (FCRs). In some cases, the authors write the first draft of the FCRs to ensure they are based on the information and analysis contained in the full report. The draft FCRs are then edited and approved by the SC. The SC deliberates in meetings closed to the public in order to develop draft FCRs free from outside influences. All analyses and drafts of the study remain confidential.

Stage 4: Report Review

As a final check on the quality and objectivity of the study, all CCST full commissioned reports must undergo a rigorous, independent external peer review by experts whose comments are provided anonymously to the authors and SC members. CCST recruits independent experts with a range of views and perspectives to review and comment on the draft report prepared by the authors and the SC. The proposed list of peer reviewers is approved by the Oversight Committee to ensure all report sections are adequately reviewed.

The review process is structured to ensure that each report addresses its approved study charge, that the findings are supported by the scientific evidence and arguments presented, that the exposition and organization are effective, and that the report is impartial and objective.

The authors and the SC must respond to, but need not agree with, reviewer comments in a detailed “response to review” that is examined by one or more independent “report monitor(s)” responsible for ensuring that the report review criteria have been satisfied. After all SC members and appropriate CCST officials have signed off on the final report, it is transmitted to the sponsor of the study and the sponsor can release it to the public. Sponsors are not given an opportunity to suggest changes in reports. All reviewer comments and SC deliberations remain confidential. The names and affiliations of the report reviewers are made public when the report is released.

Appendix G

Acknowledgements

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Improving California's Regulatory Analysis

MAC TAYLOR • LEGISLATIVE ANALYST • FEBRUARY 2017

LAO

EXECUTIVE SUMMARY

Analysis Can Help Select Preferred Regulatory Approach. The Legislature passes laws that direct agencies to implement policies, but the laws often do not identify all of the details of how those policies should be implemented. As a result, agencies evaluate different options for implementing the law and develop regulations to clarify the details. When developing regulations, agencies are required to analyze the potential effects of proposed rules—including anticipated benefits and adverse economic effects. The goal of this analysis is to help regulators evaluate trade-offs between different options and select the approach that achieves the Legislature's policy goal in the most cost-effective manner.

Senate Bill 617 Established New Requirements for Major Regulations. Chapter 496 of 2011 (SB 617, Calderon) established a new process for analyzing regulations having an estimated economic impact of greater than $50 million—known as major regulations. It required agencies to develop a more extensive regulatory analysis before major regulations are proposed. In addition, SB 617 required the Department of Finance (DOF) to (1) provide guidance on the methods that agencies should use when analyzing major regulations and (2) review and comment on the analysis before a rule is proposed.

Limitations of Current Process for Analyzing Major Regulations. Based on our review of the analyses developed under the new SB 617 process, we find that some of the changes have led to improvements in the quality and consistency of agencies' analysis of major regulations. However, we also identified the following limitations:

- ***Analyses of Major Regulations Do Not Consistently Follow Best Practices.*** In many instances, agencies did not consistently follow best practices for regulatory analysis. For example, agencies often analyzed a limited range of alternatives and did not quantify benefits and/or costs of alternatives. As a result, the likely effects of different regulatory options were often unclear, and, therefore, it is frequently difficult to know whether the proposed approaches were the most cost-effective.

- ***Certain Analytical Requirements Offer Limited Value.*** In some cases, the existing analytical requirements appear to provide information of limited value to making cost-effective regulatory decisions—which is the main goal of the analysis.

- ***No Requirement for Retrospective Review.*** There is no statewide requirement for agencies to regularly evaluate the effects of a rule after it has been implemented—also known as retrospective review. As a result, the Legislature and regulators might not have adequate information in the future to determine whether the laws or rules should be eliminated, modified, or expanded in order to better achieve statutory goals.

LAO Recommendations. We make several recommendations to ensure agencies provide information that can be used to support regulatory actions that implement legislative objectives cost-effectively.

- ***Establish More Robust Guidance and Oversight.*** We recommend the Legislature direct an oversight entity to (1) develop more detailed guidance on best practices for analysis of major regulations and (2) review updated analyses when agencies make substantial changes to a major rule after it is initially proposed. The Legislature could also consider giving this oversight entity authority to reject an agency's proposed major rule if the analysis is inadequate or does not show the rule to be cost-effective. These oversight activities could be conducted at DOF or some newly created entity with economic and analytical expertise.

- ***Reduce Requirements That Provide Limited Value.*** We recommend the Legislature identify opportunities to reduce or eliminate analytical requirements that provide limited value for assessing trade-offs and making cost-effective regulatory decisions. For example, an agency could be exempt from certain requirements if (1) it demonstrates that the analysis is not necessary to adequately compare regulatory options or (2) state or federal law limit agency discretion. Reducing unnecessary requirements would free up agency resources and allow the agency to implement regulations more quickly or focus on other aspects of regulatory analysis that likely have greater value.

- ***Require Agencies to Conduct Retrospective Review.*** We recommend the Legislature consider requiring agencies to plan for and conduct retrospective reviews for major regulations. An oversight entity should be responsible for issuing guidance on best practices for conducting these reviews and overseeing the reviews. To ensure retrospective reviews are not too administratively burdensome, the Legislature could allow the oversight entity to exempt an agency from retrospective review requirements under certain conditions, such as if collecting adequate data is infeasible or too costly.

INTRODUCTION

Chapter 496 of 2011 (SB 617, Calderon) made significant changes to the way California analyzes and reviews major regulations under the state's Administrative Procedures Act (APA). These changes were intended to promote regulations that achieve the Legislature's policy goals in a more cost-effective manner. In this report, we provide a brief description of California's regulatory process, the potential value of regulatory analysis, and the recent changes made by SB 617. Although there have been some improvements in recent years, we identify some significant limitations that still remain. We provide recommendations that are aimed at addressing these limitations by ensuring that the potential effects of regulations are thoroughly analyzed and regulators are implementing the Legislature's policy direction in the most cost-effective manner.

STATE REGULATORY PROCESS

General Overview of Regulations

Regulations Implement State Law. Broadly, regulations are rules issued by a government authority. In many cases, the Legislature passes laws that direct agencies to implement policies, but it does not clearly identify all of the details of how the policy should be implemented. As a result, agencies have to develop regulations through a rulemaking process to clarify these details. For example, the law could direct an agency to ensure businesses and/or households reduce a certain type of pollution to a specified level. If the law does not specify exactly how pollution must be reduced, the agency will establish a regulation outlining the requirements in more detail.

The APA is state law that establishes procedural requirements that state agencies must follow when they "implement, interpret, or make specific" policies established by the Legislature through the establishment of new or revised regulations. These requirements apply to rules developed by all state agencies, unless otherwise exempted by law. For example, most regulatory activities at the California Public Utilities Commission are exempt because the commission has a separate regulatory process in place. This report focuses on regulations developed by state agencies that are subject to the APA.

APA Aims to Ensure Rules Are Consistent With State Law. The APA aims to ensure that rulemaking is transparent, agencies consider public input, and regulations are consistent with state law. There are two major types of rulemaking procedures: regular and emergency. In this report, we focus on regular rulemaking. (Emergency rules are subject to somewhat different requirements.)

Figure 1 (see next page) summarizes the key steps of the regular rulemaking process. The process begins after the Legislature passes a law that gives authority to a state agency, and the state agency decides it needs to issue a rule. In some cases, the new law could require the agency to do so. The agency then develops the regulation, as well as various additional documents as summarized in Figure 2 (see page 7). Once the agency has developed its proposed rule, it publishes the Notice of Proposed Action (notice) along with the other materials. For example, as we discuss in more detail below, the agency is required to complete an analysis of various effects—including economic and fiscal effects—of the proposed rule. The agency is then required to solicit public comments and respond to those comments. The agency may also modify the proposed rule, which then triggers additional public comment period(s). The agency must submit the final rule to the Office of Administrative Law (OAL) within one year of issuing the notice, and OAL has 30 working days to review the rulemaking documents to ensure that the agency fully complied with APA procedural and legal requirements.

About 600 Regulations Submitted to OAL Annually. This total includes regular rules, emergency rules, and other minor technical adjustments to rules that are not required to go through the full rulemaking process. Many different agencies propose rules, and the number of rules proposed by each agency varies from year to year. The top ten rulemaking agencies in 2014 and 2015, in terms of the number of rules submitted to the OAL, are shown in Figure 3 (see page 8).

Regulatory Analysis Requirements

The APA requires agencies to analyze the effects of proposed rules to help justify their merit. Below, we describe some of the APA's major regulatory analysis requirements. We also describe some of the changes SB 617 made to the regulatory process and requirements for analyzing regulations.

Figure 1

Summary of Regular Rulemaking Process

Legislature

Passes law giving authority to state agency.

Agency

- Identifies need to adopt regulation to implement law.

- Develops rule and supporting documents, including economic analysis and fiscal estimate.
- May hold public workshops and meet with stakeholders.

DOF: reviews economic analysis for major rules.

- Publishes proposed rule, notice of proposed action, and other supporting documents.
- Conducts 45-day public comment period and potentially a public hearing.
- Considers comments and may change proposed rule.
- If substantial changes to rule, conducts additional public comment period (either 15 or 45 days).

DOF: must approve fiscal estimate for major and nonmajor rules.

- Finalizes rule and supporting documents.
- Submits final rule and supporting documents to OAL.

Office of Administrative Law

- Reviews rulemaking documents for compliance with APA requirements within 30 days.
- If approved, rule published. If rejected, rule returned to agency.

DOF = Department of Finance; OAL = Office of Administrative Law; and APA = Administrative Procedures Act.

General Requirements. Agencies are subject to various requirements to assess the potential effects of a regulation. For example, a proposed regulation must be based on adequate information concerning the need for, and consequences of, action. In addition, for nearly all regulations, agencies are required to provide the following information:

- ***Purpose of the Regulation.*** Agencies are required to provide an explanation for why the regulation is reasonably necessary. Agencies also have to list the specific provisions of law that are being implemented and that authorize the regulation. Senate Bill 617 added a requirement that an agency describe the problem it intends to address and how the regulation addresses the problem.

- ***Anticipated Benefits.*** Senate Bill 617 added a specific requirement that agencies identify monetary benefits and nonmonetary benefits of the regulation, such as public health, safety, and social equity.

- ***Adverse Economic Effects.*** Agencies must assess the potential for adverse economic impact on California businesses and individuals. For example, agencies are required to assess potential effects of the proposed regulation on (1) the creation or elimination of jobs within the state and (2) the creation, elimination, expansion, and competitiveness of businesses in California.

- ***Evaluation of Alternatives.*** Agencies are required to evaluate alternatives and provide reasons for rejecting the alternatives. Agencies are also required to determine, with supporting information, that no alternative approach would be more effective, or would be as effective and less burdensome to private persons. Senate Bill 617 further required that

Figure 2

Key Regulatory Documents Developed by Agencies

When Regulation Is Initially Proposed

✓ ***Regulation Text.*** The proposed language that would be added, modified, or eliminated in the California Code of Regulations.

✓ ***Notice of Proposed Action.*** A notice provided to interested parties that includes a summary of the proposed rule, the objective of the rule, and a summary of the agency's assessment of the likely effects of the rule.

✓ ***Initial Statement of Reasons (ISOR).*** The agency's primary justification for and analysis of the rule, including:
- An explanation for why the agency needs to adopt the rule.
- The agency's analysis of the likely effects of the rule (including an economic analysis or SRIA for major regulations).
- A description of reasonable alternatives to the rule and the agency's reason for rejecting those alternatives.

✓ ***Economic and Fiscal Impact Statement.*** Provides a summary of the agency's assessment of the likely economic effects, as described in the ISOR, and an estimate of the fiscal effects on state and local governments.

When Regulation Is Finalized[a]

✓ ***Final Statement of Reasons.*** An update of the information contained in the ISOR, including a summary of public comments and how the agency responded to those comments.

[a] If there are changes after the rule is initially proposed, updates to the regulation text and economic and fiscal impact statement are also included.

SRIA = Standardized Regulatory Impact Assessment.

Figure 3

Agencies With Most Rules Submitted to Office of Administrative Law in 2014 and 2015

Agency	2014
Department of Food and Agriculture	55
Fish and Game Commission	28
Department of Corrections and Rehabilitation	25
State Water Resources Control Board	25
Fair Political Practices Commission	20
Department of Social Services	19
Department of Health Care Services	18
Board of Equalization	17
California Energy Commission	14
California Horse Racing Board	13
Other	366
Total	**600**
Agency	**2015**
Department of Food and Agriculture	51
California Health Benefit Exchange	31
State Water Resources Control Board	24
Department of Insurance	23
Fish and Game Commission	22
Department of Corrections and Rehabilitation	20
Occupational Safety and Health Standards Board	18
Board of Forestry and Fire Protection	17
Air Resources Board	16
Board of Equalization	15
Other	385
Total	**622**

agencies determine that no alternative would be more cost-effective to affected private persons and equally effective in implementing statutory policy.

- ***Fiscal Effects.*** Agencies are required to estimate the fiscal effects of the regulation on state and local governments.

Agencies are also required to estimate how the regulation would affect specific groups or outcomes. For example, agencies must estimate effects on small businesses and housing costs.

SB 617 Required Additional Analysis and Oversight for "Major" Regulations. The most notable changes made by SB 617 are for regulations having an estimated economic impact of greater than $50 million—known as major regulations. Senate Bill 617 required agencies to develop a more extensive economic analysis known as a Standardized Regulatory Impact Assessment (SRIA) before a major regulation is proposed. Agencies are responsible for determining whether a regulation is major. In addition, the Department of Finance (DOF) reviews agency estimates of economic impact to ensure that agencies are submitting SRIAs for all regulations with economic impacts greater than $50 million. The analyses are intended to provide agencies and the public with tools to determine whether the proposed regulation implements the Legislature's policy decisions in a way that is cost-effective.

To ensure agencies are conducting more rigorous analyses, SB 617 required DOF to provide guidance to agencies on methodologies for developing SRIAs. This includes methods for:

- Estimating whether a regulation will have a $50 million economic impact.

- Assessing benefits and costs of a proposed regulation, expressed in monetary terms to the extent feasible, but also other nonmonetary factors such as fairness and social equity.

- Comparing proposed regulatory alternatives with an established baseline so agencies can make analytical decisions for regulations necessary to determine the most effective, or equally effective and less burdensome, alternative.

- Determining the impact of the regulation on jobs, businesses, and public welfare.

As shown in Figure 4, agencies developed 22 SRIAs from the time the law was implemented in late 2013 through 2016.

Senate Bill 617 also established a greater oversight role for DOF. In addition to issuing guidance for agencies developing SRIAs, DOF must review the SRIA before a major rule is proposed and provide comments on the extent to which the analysis adheres to its guidance. Agencies must include a summary of DOF's comments and agency responses to the comments when the rule is initially proposed, but the agencies are not required by law to update the analysis to reflect comments from DOF. Finally, DOF is available to provide technical assistance to agencies and has recently implemented a new training program.

Figure 4

SRIAs Developed for 22 Regulations Since 2014

Agency	Date Submitted to DOF	Regulation
Air Resources Board	February 2014	Amendments to Truck and Bus Regulation
	October 2014	Low Carbon Fuel Standard and Alternative Diesel Fuels
	April 2014	Oil and Gas Regulation
	June 2015	Zero Emission Vehicle Credit Amendment
	April 2016	Cap-and-trade
	December 2016	Portable Engine Airborne Toxic Control Amendment
California Energy Commission	December 2014	Water Appliance Efficiency
	August 2015	LED Efficiency
	June 2016	Computer Efficiency
Department of Insurance	January 2014	Mental Health Parity
	July 2015	Network Adequacy
CalRecycle	July 2014	Compostable Materials, Transfer/Processing
	October 2014	Used Mattress Recovery and Recycling[a]
Department of Industrial Relations	October 2014	Return-to-Work Program
	March 2016	Refinery Safety
GO-Biz	August 2014	California Competes Tax Credit
Fish and Game Commission	November 2014	Hunting: Nonlead Ammunition[a]
Department of Transportation	March 2015	Affordable Sales Program
	November 2016	Electronic Toll Collections
Health Benefits Exchange	January 2016	Eligibility and Enrollment
State Water Resources Control Board	October 2016	Drinking Water Standards
Department of Conservation	December 2016	Underground Gas Storage

[a] Regulation later determined to not exceed $50 million threshold for "major."

SRIA = Standardized Regulatory Impact Assessment ; DOF = Department of Finance; and CalRecycle = California Department of Resources Recycling and Recovery.

ANALYSIS AIMS TO CLARIFY EFFECTS AND INFORM DECISIONS

Below, we describe the primary reasons for analyzing regulations and some of the key methods for conducting good analysis.

Analysis a Tool for Improving Regulatory Outcomes. Regulators have options for how to implement state laws, and their decisions can have substantial costs and benefits for businesses and households in California. Collectively, agencies that have developed SRIAs so far have estimated billions of dollars in costs and benefits annually from these regulations. The primary goal of regulatory analysis is to inform the public, stakeholders, and government of the likely effects—good and bad—of various regulatory options. This information can then be used to evaluate the trade-offs between different options and select the preferred approach. Improved regulatory decisions have the potential to increase benefits, lower costs, and ensure benefits and costs are fairly distributed.

A regulatory analysis can take different forms—each of which is meant to provide different information that answers different questions. For example, a regulator might conduct one or more of the following: (1) a cost-benefit analysis to determine whether the overall benefits of a rule exceed the costs, (2) a cost-effectiveness analysis to determine which approach achieves a predetermined goal for the lowest overall cost, and/or (3) a distributional analysis to determine how costs and benefits are distributed among different types of households and businesses. As discussed above, California's analytical requirements primarily focus on cost-effectiveness. Regardless of which tool is used, the analysis is meant to help regulators make better, more informed decisions that implement the Legislature's policies more effectively.

Federal Government Has Long History of Regulatory Analysis. The federal government imposes a variety of requirements on federal agencies proposing regulations. These requirements largely date back to an executive order established in 1981. Although there have been some changes over the last 35 years, the key principles have largely remained in place. For example, most agencies issuing economically significant rules are required to select the approach that maximizes net benefits to society and demonstrate that the benefits of the rule justify the costs. In addition, when an agency determines a regulation is necessary, it must design the regulation in the most cost-effective manner to achieve the objective. Agencies must provide the analysis of its proposed and final regulations to the Office of Information and Regulatory Affairs (OIRA), within the President's Office of Management and Budget (OMB). OIRA is responsible for reviewing agencies' regulations and the accompanying analyses.

Federal Guidance Describes Best Practices for Regulatory Analysis. As part of its oversight, the OMB has developed best practices for analysis. Most notably, after public input and peer review, the OMB and the President's Council of Economic Advisors issued "Circular A-4" in 2003—the central guidance document designed to assist regulatory agencies. Circular A-4 identifies three key elements of an effective regulatory analysis:

- Statement of need for regulatory action.
- Clear identification and examination of a range of regulatory approaches.
- Evaluation of the costs and benefits—quantitative and qualitative—of the

proposed regulatory action and the main alternatives.

It also offers more specific guidance on the basic methods that should be used for analysis. A summary of this guidance is shown in Figure 5.

Regulatory Analysis Has Some Trade-Offs. Although analysis has the potential to help inform better regulatory decisions, there are also trade-offs. First, detailed analysis takes time and resources for regulators. This results in additional administrative costs that are ultimately paid for by businesses and households in the form of higher fees and taxes. Second, analysis can result in delays in implementing policies. Third, some have criticized regulatory analysis, particularly cost-benefit analysis, as being biased against regulations that benefit health, welfare, and safety. This is because the costs of a regulation are often easier to quantify than the broad types of societal benefits that can result from such regulation. For example, the costs of a new regulation requiring a specific pollution control technology might be easier to estimate than the improved health effects of lower pollution and the value of those health benefits. To the extent decision-makers give greater weight to effects that can be quantified, the analysis

Figure 5

Summary of Federal Guidance for Regulatory Analysis

✓ **Describe Need for Regulatory Action.** Explain need for regulation and how the regulatory action will meet that need.

✓ **Define Baseline.** Estimate what the world would be like absent the action, including changes in the market and the effect of other regulations.

✓ **Set Time Horizon for Analysis.** Cover time frame long enough to capture all the important benefits and costs likely to result from the rule.

✓ **Identify a Range of Regulatory Alternatives.** Alternative approaches could include:

- Market-oriented approaches rather than command and control.
- Performance standards rather than design standards.
- Informational measures.
- Different enforcement methods, stringencies, compliance dates, and requirements based on firm size or location.

At a minimum, agencies should compare their preferred option with more stringent and less stringent alternatives. When the preferred option includes a number of distinct provisions, the benefits and costs of each provision should be analyzed separately.

✓ **Identify Consequences of Regulatory Alternatives.** Identify the potential benefits and costs for each alternative and the timing of benefits and costs. This could include analysis of co-benefits and a distributional analysis that characterizes where benefits and costs are likely to accrue. To the extent feasible, quantify and monetize benefits and costs. Use discounting to assess benefits and costs that occur over different time horizons. Identify important benefits and costs that are difficult or impossible to quantify or monetize and how they affected the regulatory choice.

✓ **Characterize Uncertainty in Benefits and Costs.** Analyze important uncertainties connected with a regulatory approach and describe the range of plausible benefits and costs.

✓ **Summarize the Regulatory Analysis.** Include one or more tables that summarize the benefit and cost estimates for each regulatory action and alternative under consideration, including benefits and costs that cannot be monetized or quantified. Agency should also report distributional effects.

Source: Office of Management and Budget's Circular A-4.

could encourage regulators to reject more stringent alternatives that achieve additional, non-monetized benefits that outweigh the additional costs. To help avoid this potential issue, good regulatory analysis should clearly identify all significant types of benefits and costs, including those that are hard to quantify, so they are considered when making regulatory decisions.

LAO ASSESSMENT

We reviewed (1) the APA's analytical requirements, (2) the SRIA guidance issued by DOF, and (3) the SRIAs that agencies have developed so far. The purpose of our review was to examine whether state agencies are conducting high-quality analyses of major regulations and whether the analyses provide information that helps ensure regulations are implemented in a cost-effective manner. Our review focused on analysis of major regulations because they represent a disproportionately large percentage of the overall costs and benefits of state regulations. (See the nearby box for a brief discussion of nonmajor regulations, which were not the focus of this report.) Based on our review, we identify several limitations, which are summarized in Figure 6 and discussed in detail below.

Analyses of Major Regulations Do Not Consistently Follow Best Practices

We find that the new SB 617 requirements have increased the consistency of agencies' analyses and, as a result of the additional DOF oversight, agency analyses of proposed rules are often more robust and higher quality. Despite some improvements, however, we identified many instances where state agencies did not consistently follow best practices for regulatory analysis, such as those outlined earlier in Figure 5. As a result, the likely effects of different regulatory options are often unclear and it is difficult to know whether the proposed regulatory approaches are the most cost-effective. We discuss the major limitations in more detail below.

Benefits and Costs of Alternatives Not Quantified. The costs and benefits of regulatory options—including the preferred approach, as well as alternatives—are often unmeasured or unclear. This makes it difficult to determine why the proposed regulation is preferable to alternatives. For example, the California Department of Resources Recycling and Recovery's SRIA for the Compostable Materials regulation—which made

Figure 6

Summary of LAO Findings

✓ **Analyses of Major Regulations Do Not Consistently Follow Best Practices**
- Benefits and costs of alternatives not quantified.
- Limited range of alternatives analyzed.
- Future benefits and costs not discounted.
- Limited assessment of uncertainty.
- Distributional analysis often lacking.
- Limited guidance and oversight contribute to shortcomings.

✓ **Certain Analytical Requirements for Major Regulations Offer Limited Value**
- Macroeconomic analyses less useful than evaluating direct effects.
- Analysis of regulations with limited feasible alternatives.

✓ **No Requirement for Retrospective Review** changes to the way solid waste facilities must handle compostable materials—did not quantify the environmental benefits of any of the options it considered. This makes it difficult to assess the trade-offs between the different options. In addition, the SRIA for the Air Resources Board's (ARB's) revisions to the Bus and Truck Regulation—which delayed requirements for truck owners to install new pollution control technologies or purchase cleaner engines—did not clearly quantify how alternatives to the proposed rule would affect industry costs or the level of air pollution emissions.

Limited Range of Alternatives Analyzed. In most cases, agencies have options for how they can implement a law, such as how stringent a requirement to impose, as well as what specific rules to impose. State law directs agencies to describe reasonable alternatives and the agencies' reasons for rejecting those alternatives. In our view, SRIAs generally included an analysis of too few alternatives. As a result, agencies might have ignored some potentially viable alternatives. Most SRIAs included an examination of two alternatives to the proposed regulation. This may be reasonable in some cases where limited feasible alternatives exist. In most cases, however, an analysis of a greater range of alternatives could generate valuable information about which approach is the most cost-effective or generates the greatest net benefits. For example, additional analysis of the following types of alternatives could help inform the agency's action:

- ***Subparts of a Regulation.*** Some regulations are complicated and multifaceted with multiple distinct components. Yet, SRIAs did not always include an analysis of these distinct components of a regulation. For example, the SRIA for ARB's extension of the cap-and-trade regulation did not include an analysis of the effects of specific parts of the program, such as linking the state's program with Ontario. Therefore, the degree to which linking with Ontario would affect the overall costs and benefits is unclear.

Oversight and Guidance for Nonmajor Regulations Less Robust

This report focuses on major regulations, but there are actually far more nonmajor rules. Although we did not review agencies' analyses of nonmajor rules, many of the statutory requirements are the same. For example, agencies are required to adopt the most cost-effective regulatory approaches and estimate effects on jobs, businesses, and small businesses. However, the Department of Finance (DOF) provides much less guidance and oversight over the analyses. Much of DOF's review focuses on state and local fiscal effects. There is limited review of methods used to estimate overall benefits and costs, including costs to private parties and environmental improvements. In the future, the Legislature might want to consider changes to the analytical requirements and processes for nonmajor rules in a way that improves the quality of analysis and/or removes unnecessarily burdensome requirements. For example, once the Legislature is comfortable that the current standardized regulatory impact assessment process is leading to improved regulatory decisions and the analytical requirements are not overly burdensome, it could consider extending the process to other regulations, such as some regulations that have an economic impact of less than $50 million annually.

- ***Different Stringencies.*** Some SRIAs evaluated a limited range of different stringencies. For example, the State Water Resources Control Board proposed a new drinking water standard for 1,2,3-Trichloropropane—a chemical that was not previously regulated. The SRIA included a comparison of the proposal to two alternatives: do nothing (not imposing a new standard) and a slightly less stringent standard than the proposed regulation. It would have been helpful to estimate the costs and benefits of a broader range of feasible standards—such as a more stringent standard and additional less stringent options. This would provide a better understanding of trade-offs associated with a broader range of feasible options which could be used to ensure the proposed standard is the best option for meeting the statutory goals.

- ***Alternatives Outside the Scope of the Rulemaking.*** Some regulations were not compared to alternatives outside the scope of the regulation. For example, the ARB's Low Carbon Fuel Standard (LCFS) regulation aims to reduce greenhouse gas (GHG) emissions by reducing the carbon content of fuel. The SRIA did not include a comparison of the costs of LCFS to other policies that can reduce GHG emissions, such as cap-and-trade or more stringent vehicle efficiency standards. Comparing a regulation to options outside the scope of the rulemaking is particularly important when agencies have broad authority to issue multiple regulations to achieve a particular goal. Such authority has been given to the ARB to regulate air pollution and GHG emissions. However, this type of authority is relatively rare in California.

Future Benefits and Costs Not Discounted. It is a standard analytical practice to weight benefits and costs that occur in the future less than those that occur more immediately. To help policymakers evaluate regulations that have benefits and costs that occur at different times, analyses typically use a method known as discounting—whereby future benefits and costs are adjusted downward based on how far in the future they occur. Agency SRIAs did not always include discounted future benefits and costs. For example, the California Energy Commission (CEC) energy efficiency standards for computers and monitors were expected to increase initial equipment costs, but generate future consumer savings from lower energy bills. However, the future savings were not discounted. As a result, the analysis overstates the overall benefits of the efficiency rule.

Limited Assessment of Uncertainty. For any regulatory approach that is adopted, the exact consequences of the regulation are uncertain. Therefore, it can be important to identify a range of outcomes that could occur and assess the likelihood of each outcome—referred to as sensitivity analysis. This provides the agency and the public with a better understanding of the risks—both positive and negative—of a particular approach. Several agencies had little or no analysis of uncertainty in the SRIA. For example, the California Department of Transportation's (Caltrans') analysis of the Affordable Sales Program—a program to dispose of surplus residential property owned by Caltrans—did not estimate how benefits would differ under different assumptions about future real estate property values, which can be subject to substantial uncertainty. A sensitivity analysis that assessed the benefits under different property value assumptions could have, for example, provided information about whether there were scenarios under which the proposed approach would have yielded insufficient benefits to justify the costs.

Distributional Analysis Often Lacking. There is often limited discussion of how the benefits and costs of the regulation would be distributed among different communities and households. Distributional effects might be an important consideration when evaluating alternatives if either benefits or costs disproportionately accrue to certain types of businesses and households, such as low-income households. For example, the CEC's analysis of the regulation establishing energy efficiency standards for LED light bulbs did not provide information on how the effects of the regulation—including the up-front costs of more expensive light bulbs, savings on electricity bills from more efficient light bulbs, and reduced pollution associated with electricity generation—would be distributed among households with different levels of income or in different parts of the state.

Limited Guidance and Oversight Contribute to Shortcomings. Limited guidance and oversight likely contribute to many of the analytical issues identified above. DOF and OAL provide guidance on what impacts agencies need to analyze and estimate in order to comply with APA requirements. In addition, for major regulations, the guidance issued by DOF provides some useful, more detailed guidance on analytical methods. However, relative to the federal guidance, it is incomplete. For example, there is little or no guidance for (1) discounting future benefits and costs, (2) identifying a potential range of alternatives to analyze, or (3) characterizing uncertainty.

Oversight of agency analysis is also still limited. Although most regulations are subject to OAL review, OAL largely reviews whether agencies comply with the APA's procedural and legal requirements. For example, OAL reviews whether the agency has provided the information required in statute and adequately responded to public comments. OAL generally does not have the responsibility, or expertise, to evaluate the quality of the agency's analysis. DOF provides some additional oversight, but its role is limited in the following ways:

- ***Review After Rule Is Initially Proposed.*** DOF is not required to review an updated SRIA if the agency modifies the proposed rule or if new information about the effects of the rule becomes available. For example, ARB made substantial changes to its recent cap-and-trade regulation that affects how millions of allowances—worth hundreds of millions of dollars annually—are allocated to businesses. These changes could have significant implications for business competitiveness and GHG emissions, but there is no requirement for DOF to review an updated SRIA.

- ***Authority to Require Changes.*** Although DOF issues guidance and comments on the SRIA, it has no legal authority to require agencies to change the analysis, consider additional alternatives, or provide additional analytical justification for the regulatory decision. Also, it does not have the authority to reject or modify proposals that do not meet legislative goals and/or are not cost-effective.

Certain Analytical Requirements for Major Regulations Offer Limited Value

In some cases, the existing analytical requirements appear to provide limited valuable information that can be used to inform cost-effective regulatory decisions—which is the main goal of the analysis. We discuss these particular requirements below.

Macroeconomic Analyses Less Useful Than Evaluating Direct Effects. A significant part of the analysis in the SRIA is devoted to estimating effects on such things as statewide employment and economic activity—sometimes known as macroeconomic effects. This focus is largely driven by the APA's requirement to assess certain adverse economic effects of a regulation, such as effects on jobs and businesses. Before conducting the macroeconomic analysis, agencies estimate the regulation's direct costs (such as costs to install a new technology) and direct benefits (such as reduced pollution or savings from reduced energy consumption). Most agencies then contract with an outside consultant, which has a model that attempts to estimate how the direct effects would change statewide macroeconomic outcomes. For example, the model might estimate how requiring a businesses to purchase technology to control pollution would affect employment, prices, production, and investment—including for businesses that purchase the technology, businesses that sell the technology, and other businesses that are indirectly affected by these changes.

These macroeconomic analyses have the following limitations that reduce their value for making cost-effective regulatory decisions:

- ***Significant Uncertainty.*** The models used to estimate macroeconomic effects rely on a wide variety of assumptions that are subject to significant uncertainty. For example, the model has to make assumptions about how an increase in costs to a business would affect prices for its product, new investments, employment, and wages for employees. Furthermore, the model has to make assumptions about how those employees will spend their money and how that affects other businesses in the economy. As a result, the findings are more uncertain than a simple assessment of direct costs and benefits.
- ***Less Transparency.*** Given the complexity of many macroeconomic models, it is often difficult for the public and stakeholders to evaluate some of the underlying assumptions in the models. As discussed above, these models typically make assumptions about business and household behavior that can have significant effects on the overall results, yet most stakeholders are unable to fully vet these assumptions and understand how they affect the final results.

Based on our review of the discussion of alternatives in the SRIAs, agencies rarely used the results from the macroeconomic analysis to justify the agency's approach and its decision to reject other options. Instead, agencies largely use the assessment of direct costs or benefits as the basis for their decisions to reject alternative approaches.

In our view, relying on high-quality assessments of direct effects is a reasonable approach in most cases. Even if policymakers are concerned about macroeconomic outcomes, estimates of direct costs and benefits are often sufficient for understanding the direction and relative scale of overall macroeconomic effects. For example, an energy efficiency regulation that results in large energy savings for very little cost will likely have substantial positive effects on macroeconomic economic conditions. A macroeconomic analysis is likely not necessary to make this basic determination, nor is it needed to determine that alternatives with higher energy savings and/or lower compliance costs will have greater positive effects.

Analysis of Regulations With Limited Feasible Alternatives. Although an analysis of alternatives is typically one of the most important aspects of a regulatory analysis, it is less valuable when few feasible alternatives exist, such as when state or federal law limits agency discretion. As a result, agencies may spend time and resources to develop the SRIA with little added benefit. This appeared to be an issue for a couple of agencies developing SRIAs. For example, the Governor's Office of Business and Economic Development (GO-Biz) estimated the economic effects of a regulation to implement the California Competes Tax Credit, which was established by the Legislature and provides up to $200 million in annual tax credits for businesses. The law establishing the tax credit also identified 11 criteria that the agency must consider when awarding credits. Therefore, the range of feasible alternatives was limited because many of the key characteristics of the program were already established in law. As a result, the agency's SRIA largely focused on different administrative approaches to evaluating applications, such as whether GO-Biz would conduct a more extensive review of applications when they are initially submitted or after first relying on an up-front screening process. The difference in the overall benefits and costs of the program under these options is unclear, but likely minor.

No Requirement for Retrospective Review

Evaluating the effects of a rule after it has been implemented is known as retrospective review. The primary goal of a retrospective review is to assess whether the regulation had the intended effect. For example, did the rule result in the expected environmental or safety improvements? Was it more or less costly than the agency expected? Such information can improve accountability and oversight. In addition, it encourages agencies to assess the main factors that led to unexpected outcomes. Policymakers can then use the information to decide whether the law or the rule should be eliminated, modified, or expanded. The federal government requires agencies to incorporate plans for conducting a retrospective review as part of rulemaking.

Unlike major state programs that are annually reviewed in the budget process, regulations are not regularly reviewed. In addition, although the APA requires agencies to analyze the potential effects of a regulation before it is adopted, there is no statewide requirement for agencies to conduct retrospective reviews of regulations. As a result, agencies proposing major rules do not include a plan for conducting retrospective reviews, and outcomes are not consistently assessed. For example, agencies do not identify the data and methods that would be used to evaluate the program in the future. Consequently, agencies generally do not incorporate into their regulations specific data collection and reporting requirements needed to evaluate the actual outcomes of their regulations after they are implemented.

LAO RECOMMENDATIONS

Below, we provide recommendations aimed at improving analysis of major regulations in California. The primary goal of these recommendations is to ensure agencies provide information that can be used to support regulatory actions that implement legislative objectives with greater benefits and/or lower costs.

Establish More Robust Guidance and Oversight

We recommend the Legislature establish a more robust system for regulatory guidance and oversight. In our view, this should include requiring an oversight entity to:

- Develop more detailed guidance on best practices for analysis of major regulations, including (1) discounting, (2) identifying and analyzing an adequate range of alternatives, (3) assessing uncertainty, and (4) clearly describing the distribution of benefits and costs across different types of businesses and households. The guidance could largely be based on Circular A-4.

- Review updated SRIAs when agencies make substantial changes to a rule after it is initially proposed or if agencies receive significant new information about the potential effects of a regulation.

We further recommend that the Legislature consider giving the oversight entity the authority to reject proposed rules that do not include an adequate analysis and/or do not demonstrate cost-effectiveness.

Determining Appropriate Oversight Entity. The Legislature has different options for which oversight entity should conduct these activities, including DOF or some newly created entity. These options have trade-offs. For example, locating these activities in DOF would build on existing expertise for reviewing SRIAs. To ensure the regulatory review process at DOF does not focus too heavily on fiscal effects at the expense of broader social effects, the Legislature could consider creating a separate office within DOF that focuses solely on regulatory review similar to OIRA at the federal level. Alternatively, the Legislature could create a new oversight entity that focuses exclusively on reviewing agencies' analyses of regulatory proposals. For example, it could create a new commission comprised of appointees from the Governor and both houses of the Legislature that operates more independently from the executive branch.

Providing Additional Resources. It is important that the administration have adequate resources to conduct timely and high-quality analysis. Providing additional guidance and oversight would have some relatively minor administrative costs. For example, doubling DOF's current staffing of a couple of full-time people would cost only several hundred thousand dollars annually, but could improve analysis and promote regulations that achieve state policy goals at significantly lower overall cost to businesses and households.

Identify Opportunities to Reduce Requirements That Provide Limited Value

We recommend the Legislature identify opportunities to reduce or eliminate analytical requirements that provide limited value for assessing trade-offs and making cost-effective regulatory decisions. The Legislature could eliminate these requirements in statute or give an oversight entity discretion to exempt agencies in specified circumstances. As part of this effort, the Legislature could consider directing the administration to report on the current requirements that provide the least value for making regulatory decisions, relative to the cost of conducting the analysis. For example, an agency could be exempt from modeling statewide macroeconomic effects if it demonstrates that direct costs are relatively small and the analysis is not necessary to adequately compare regulatory alternatives. In addition, the Legislature might want to exempt agencies from certain requirements if they demonstrate that state or federal law limits agency discretion.

Reducing unnecessary requirements would free up agency resources and staff time for other activities. The freed up resources could be used to help the agencies implement regulations more quickly or focus on aspects of regulatory analysis that likely have greater value. For example, agencies could devote more resources to estimating direct costs and benefits of alternatives or conducting retrospective reviews.

Require Agencies to Conduct Retrospective Reviews

We recommend the Legislature consider requiring agencies to plan for retrospective reviews when proposing a major regulation. Agencies would be responsible for carrying out the reviews, although they could have the option to contract with an outside organization. An oversight entity—such as DOF or a newly formed entity, in consultation with outside experts—could be responsible for issuing guidance on best practices for conducting these reviews and overseeing the reviews. Better information about the effects of regulations after they are implemented can improve accountability, oversight, and future regulatory actions.

Agencies would likely have additional costs to conduct the reviews. The amount of costs are unclear and would vary for each regulation depending on its characteristics and the proposed strategy for conducting the retrospective review. However, given the size of overall economic effects of major regulations (over $50 million annually), if these additional resources resulted in even a small increase in regulatory benefits and/or decrease in regulatory costs, the statewide benefits would likely far outweigh state fiscal costs. To ensure retrospective reviews are not too administratively burdensome, the Legislature could allow the oversight entity to exempt an agency from retrospective review requirements under certain conditions, such as if the agency demonstrates that it would be infeasible or too costly to collect adequate data.

CONCLUSION

Senate Bill 617 enhanced guidance and oversight of agency analysis of major regulations in California. However, based on our review of the analyses of major regulations conducted so far, the analyses still do not consistently follow best practices. These limitations make it difficult to understand trade-offs associated with different regulatory options and determine which options are most cost-effective. In addition, certain analytical requirements appear to provide limited value and there is no statewide requirement for agencies to conduct retrospective reviews. As a result, we recommend the Legislature direct the administration to establish more robust guidance and oversight of major regulations, identify opportunities to reduce analytical requirements that provide limited value, and require agencies to plan for and conduct retrospective reviews.

LAO Publications

This report was prepared by Ross Brown and reviewed by Brian Brown. The Legislative Analyst's Office (LAO) is a nonpartisan office that provides fiscal and policy information and advice to the Legislature.

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Attorney General Bonta Announces Lawsuit Against Oil and Gas Companies for Misleading Public About Climate Change

Saturday, September 16, 2023

Contact: (916) 210-6000, agpressoffice@doj.ca.gov

California becomes the largest geographic area and the largest economy to sue giant oil companies

OAKLAND — Joined by California Governor Newsom, California Attorney General Rob Bonta today announced the filing of a lawsuit against five of the largest oil and gas companies in the world — Exxon Mobil, Shell, Chevron, ConocoPhillips, and BP — and the American Petroleum Institute (API) for allegedly engaging in a decades-long campaign of deception and creating statewide climate change-related harms in California. Filed in San Francisco County Superior Court, the complaint asserts that although the companies have known since at least the 1960s that the burning of fossil fuels would warm the planet and change our climate, they denied or downplayed climate change in public statements and marketing. As detailed in the complaint, California has spent tens of billions of dollars to adapt to climate change and address the damages climate change has caused so far, and the state will need to spend multiples of that in the years to come. Attorney General Bonta, on behalf of the people of California, is seeking nuisance abatement through the creation of a fund to finance climate mitigation and adaptation efforts; injunctive relief to both protect California's natural resources from pollution, impairment, and destruction as well as to prevent the companies from making any further false or misleading statements about the contribution of fossil fuel combustion to climate change; damages; and penalties.

"Oil and gas companies have privately known the truth for decades — that the burning of fossil fuels leads to climate change — but have fed us lies and mistruths to further their record-breaking profits at the expense of our environment. Enough is enough," **said Attorney General Rob Bonta**. "With our lawsuit, California becomes the largest geographic area and the largest economy to take these giant oil companies to court. From extreme heat to drought and water shortages, the climate crisis they have caused is undeniable. It is time they pay to abate the harm they have caused. We will meet the moment and fight tirelessly on behalf of all Californians, in particular those who live in environmental justice communities."

"For more than 50 years, Big Oil has been lying to us — covering up the fact that they've long known how dangerous the fossil fuels they produce are for our planet," **said Governor Gavin Newsom**. "California taxpayers shouldn't have to foot the bill for billions of dollars in damages — wildfires wiping out entire communities, toxic smoke clogging our air, deadly heat waves, record-breaking droughts parching our wells. With this lawsuit, California is taking action to hold big polluters accountable and deliver the justice our people deserve."

The complaint contains extensive evidence demonstrating that the defendants have long known about the catastrophic results caused by the use of fossil fuels. For instance, in 1968, API and its members received a report from the Stanford Research Institute, which it had hired to assess the state of research on environmental pollutants, including carbon dioxide. The report stated: “Significant temperature changes are almost certain to occur by the year 2000, and . . . there seems to be no doubt that the potential damage to our environment could be severe.” In 1978, an internal Exxon memo stated that “[p]resent thinking holds that man has a time window of five to ten years before the need for hard decisions regarding changes in energy strategies might become critical.” More recently, the defendants have deceptively portrayed themselves and their products as part of the climate solution. For example, Shell claims online that it aims to become a net-zero emissions energy business by 2050, and that it is “tackling climate change.” However, Shell’s CEO told the BBC on July 6, 2023 that cutting oil and gas production would be “dangerous and irresponsible.”

The complaint includes the following causes of action:

- **Public nuisance**: Under California law, a “nuisance” is “anything which is injurious to health,” and a “public nuisance” is “one which affects at the same time an entire community or neighborhood, or any considerable number of persons.” The complaint alleges that all the defendants, by their deceptions, acts, and omissions, have created, contributed to, and assisted in creating harmful climate-related conditions throughout California.
- **Damage to natural resources**: California law authorizes the Attorney General to take legal action to protect the state’s natural resources “from pollution, impairment, or destruction.” The complaint alleges that the misconduct by all the defendants has served to exacerbate the climate crisis in California, and has led to the pollution, impairment, and destruction of California’s natural resources.

- **False advertising**: California law prohibits untrue and misleading advertising in connection with the disposition of property or services. The complaint alleges that all defendants, with the intent to induce members of the public to purchase and utilize fossil fuel products, made misleading statements concerning fossil fuels.
- **Misleading environmental marketing**: Under California law, "[i]t is unlawful for a person to make an untruthful, deceptive, or misleading environmental marketing claim, whether explicit or implied." The complaint alleges that all defendants have made environmental marketing claims that are untruthful, deceptive, and/or misleading, whether explicitly or implicitly.
- **Unlawful, unfair, and fraudulent business practices**: California law prohibits unlawful, unfair, or fraudulent business acts or practices. The complaint alleges that all defendants committed unlawful acts by, among other things, deceiving the public about climate change and affirmatively promoting the use of fossil fuels while knowing that fossil fuels would lead to devastating consequences to the climate, including in California.
- **Products liability (strict and negligent)**: The complaint alleges that, as a result of the defendants' failure to warn about the climate-related harms related to the use of their products, California has sustained a plethora of injuries and damages, including to state property, state infrastructure, and its natural resources.

In addition to filing the lawsuit announced today, Attorney General Bonta has supported states and municipalities that have filed their own complaints to hold major fossil fuel-producing companies accountable for their campaign of deception that has worsened the climate crisis. In August and September 2021, Attorney General Bonta filed amicus briefs supporting such efforts by the City of Honolulu and the County of Maui; the City of Baltimore; the state of Rhode Island; and the State of Minnesota. On April 7, 2023, he filed an amicus brief in the District of Columbia Court of Appeals in support of the

District of Columbia's efforts. On May 12, 2023, he led a multistate coalition in filing an amicus brief in the Ninth Circuit Court of Appeals supporting the efforts by the City of Oakland as well as the City and County of San Francisco.

Since taking office in 2021, Attorney General Bonta has been a national leader in efforts to protect the environment. On April 28, 2021, he announced an expansion of the California Department of Justice’s Bureau of Environmental Justice – the first of its kind in a state attorney general’s office. On April 28, 2022, he announced an investigation into the fossil fuel and petrochemical industries for their role in causing and exacerbating the global plastics pollution crisis. On November 10, 2022, he announced a lawsuit against major manufacturers of per- and polyfluoroalkyl substances — commonly referred to as PFAS or toxic "forever chemicals” — for endangering public health, causing irreparable harm to the state's natural resources, and engaging in a widespread campaign to deceive the public.

A copy of the lawsuit can be found **here**.

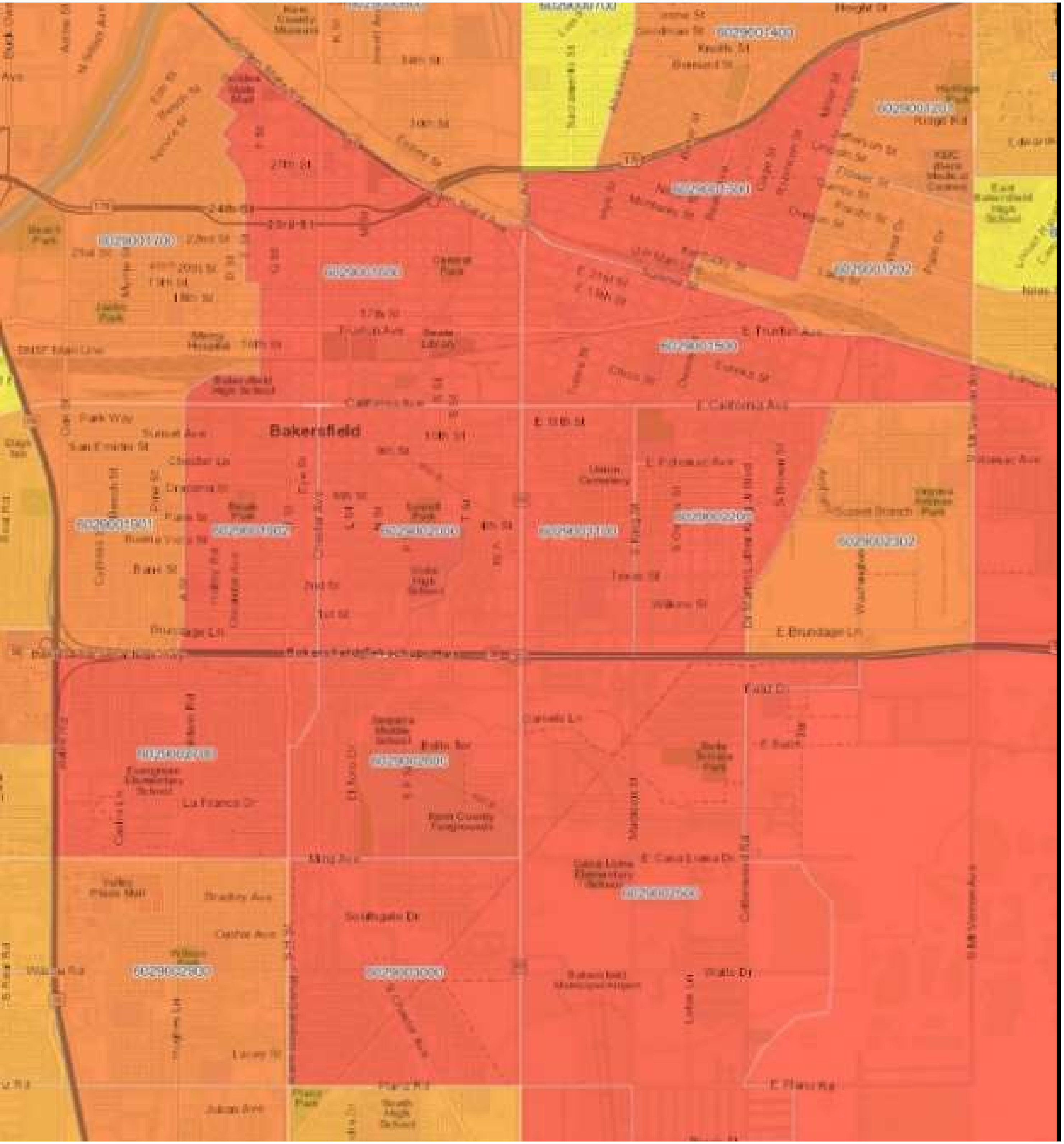
# # #

Census Tract Screenshots
Excerpted from
California Office of Environmental Health Hazard Assessment, *CalEnviroScreen 4.0 Results Map*, Compiled June 2-3, 2024
By Earthjustice

https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40

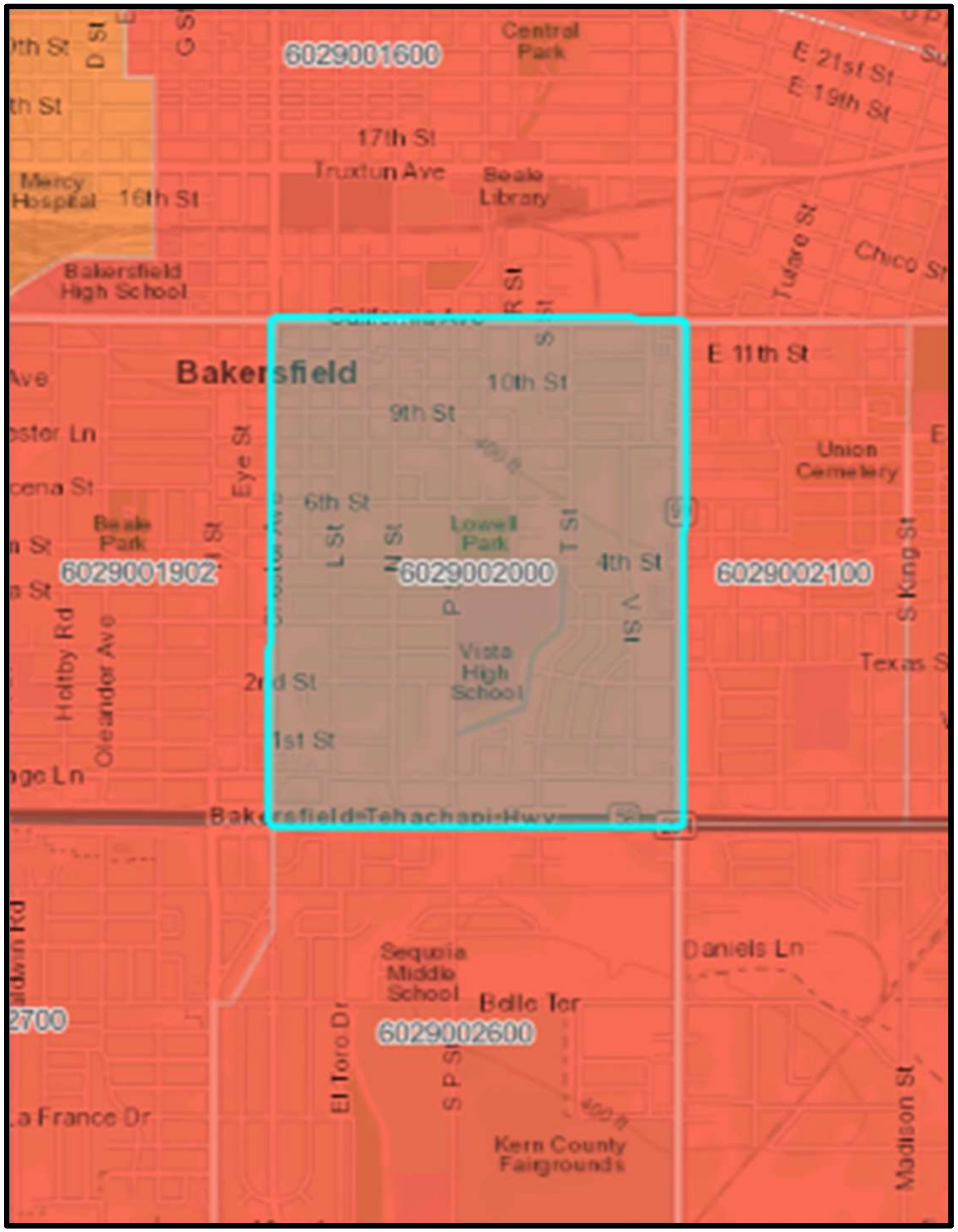

Overall Percentile
CalEnviroScreen 4.0 Results
>90 - 100 (Highest Scores)
>80 - 90
>70 - 80
>60 - 70
>50 - 60
>40 - 50
>30 - 40
>20 - 30
>10 - 20
0 - 10 (Lowest Scores)
CalEnviroScreen 4.0 High Pollution, Low Popula


Carson City
NEVADA
Sacramento
San Francisco
San Jose
MOJAVE DESERT
CALIFORNIA
Los Angeles
San Diego
Tijuana
Mexicali



Bakersfield Area Census Tracts

Bakersfield-Area Census Tracts



Census Tract: 6029002000
(Population: 6,941)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	99
Pollution Burden Percentile	89
Population Characteristics Percentile	99

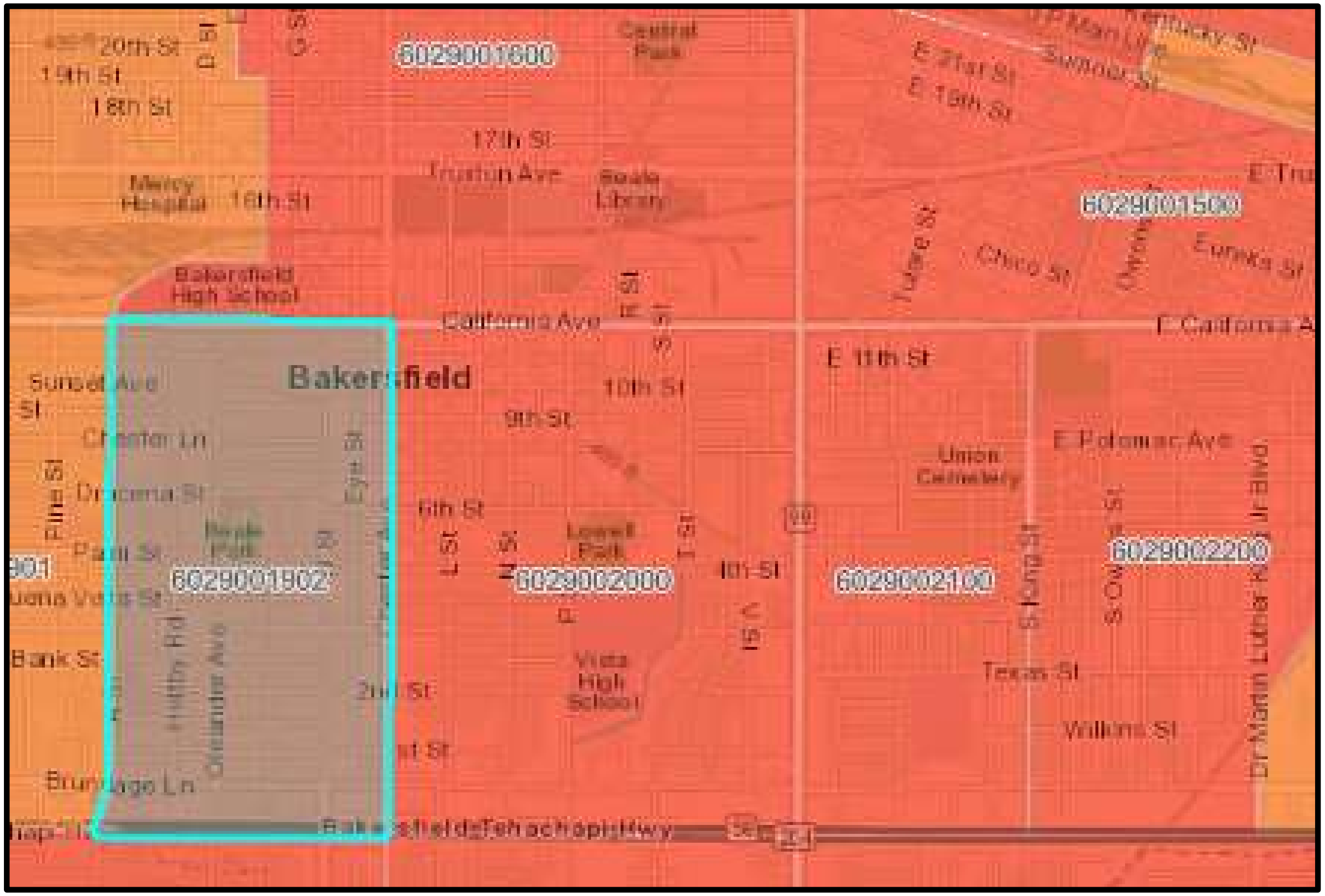
Exposures	
Ozone	94
Particulate Matter 2.5	100
Diesel Particulate Matter	91
Toxic Releases	16
Traffic	51
Pesticides	0
Drinking Water	70
Lead from Housing	84

Environmental Effects	
Cleanup Sites	77
Groundwater Threats	47
Hazardous Waste	63
Impaired Waters	0
Solid Waste	64

Sensitive Populations	
Asthma	95
Low Birth Weight	88
Cardiovascular Disease	93

Socioeconomic Factors	
Education	86
Linguistic Isolation	83
Poverty	99
Unemployment	97
Housing Burden	88

Bakersfield-Area Census Tracts



Census Tract: 6029001902
(Population: 4,595)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	92
Pollution Burden Percentile	85
Population Characteristics Percentile	87

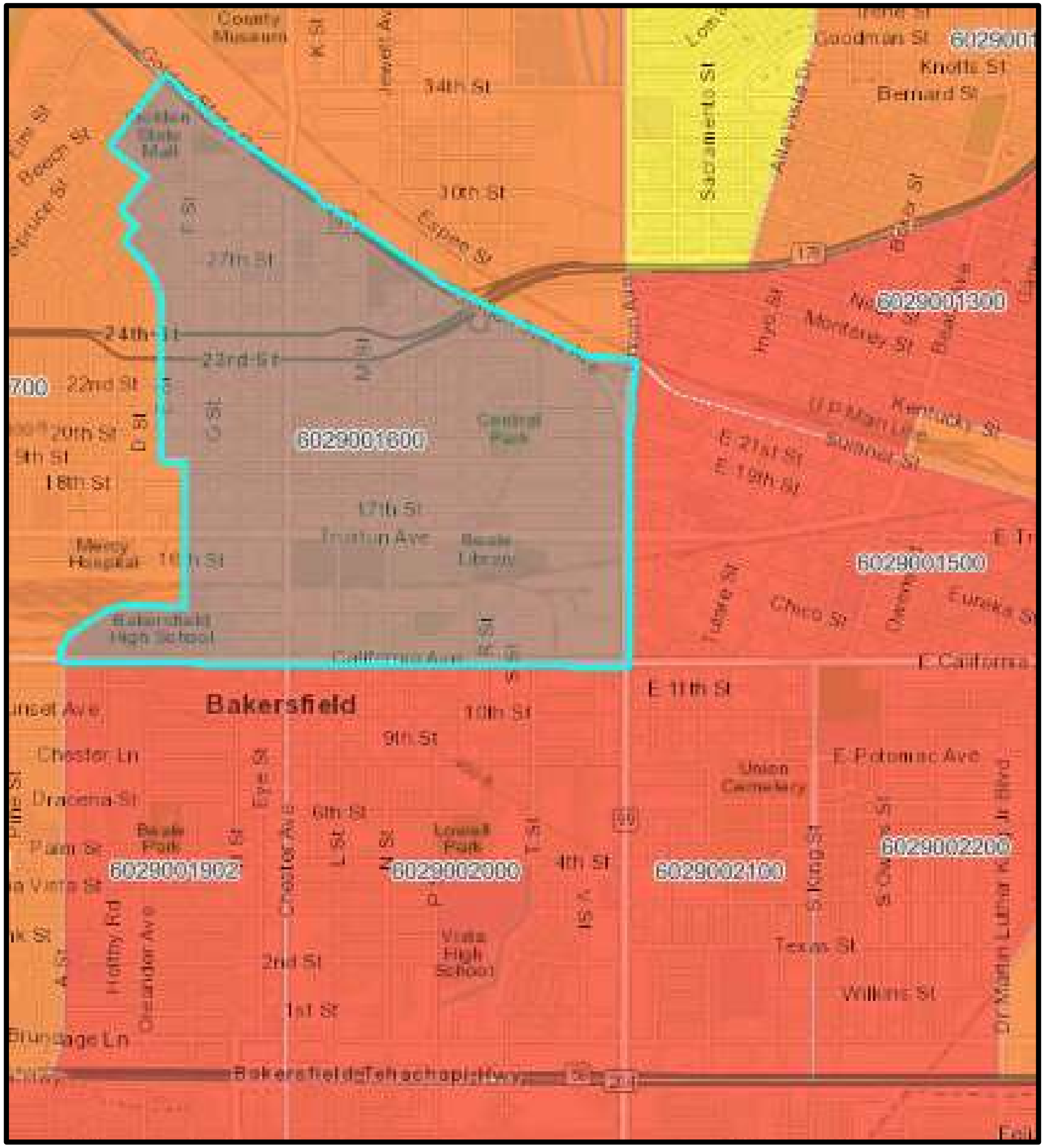
Exposures	
Ozone	94
Particulate Matter 2.5	100
Diesel Particulate Matter	85
Toxic Releases	17
Traffic	43
Pesticides	0
Drinking Water	70
Lead from Housing	88

Environmental Effects	
Cleanup Sites	81
Groundwater Threats	25
Hazardous Waste	70
Impaired Waters	0
Solid Waste	53

Sensitive Populations	
Asthma	97
Low Birth Weight	73
Cardiovascular Disease	97

Socioeconomic Factors	
Education	70
Linguistic Isolation	32
Poverty	90
Unemployment	43
Housing Burden	71

Bakersfield-Area Census Tracts



Census Tract: 6029001600
(Population: 1,967)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	95
Pollution Burden Percentile	83
Population Characteristics Percentile	96

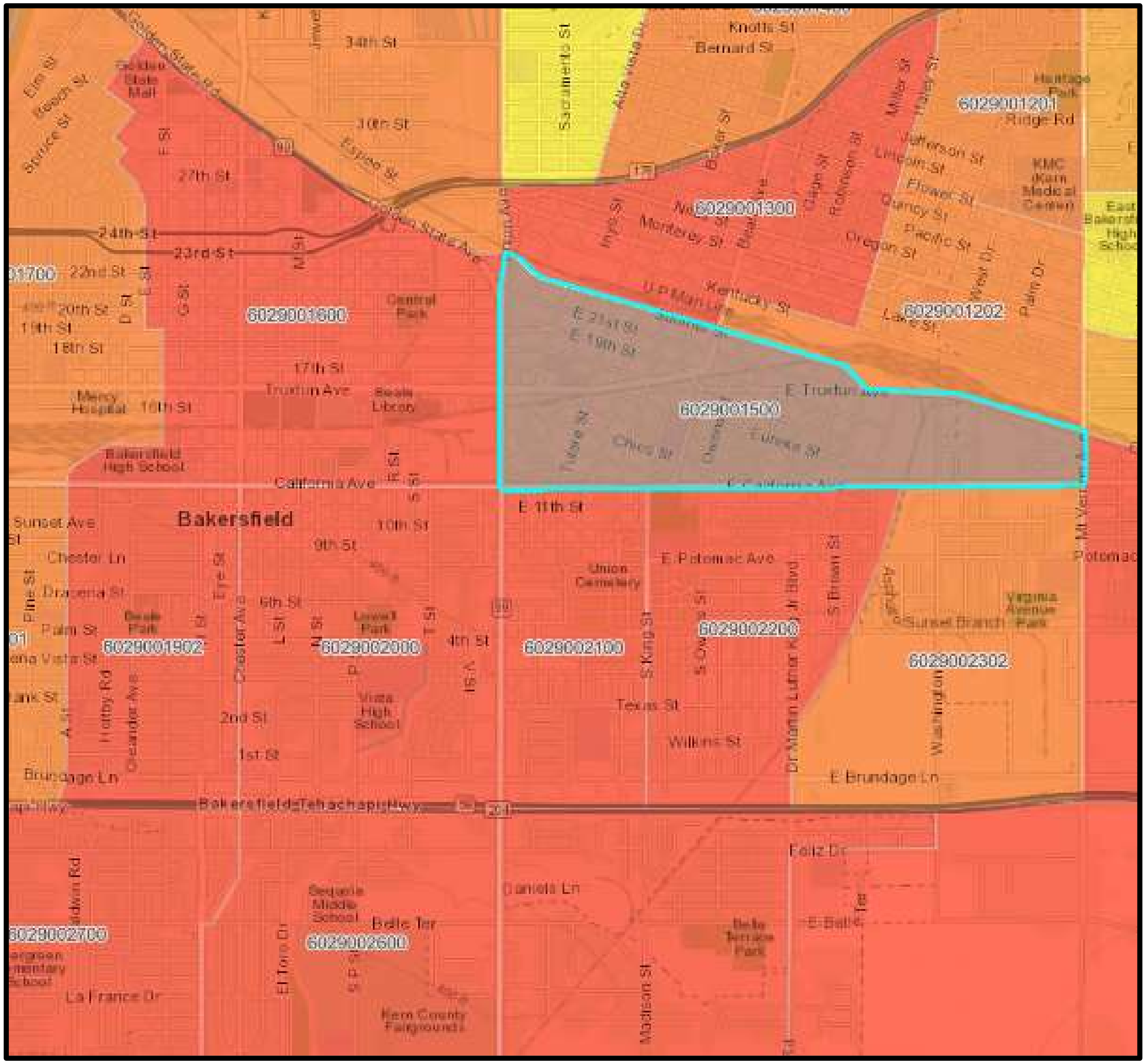
Exposures	
Ozone	94
Particulate Matter 2.5	100
Diesel Particulate Matter	97
Toxic Releases	18
Traffic	30
Pesticides	0
Drinking Water	70
Lead from Housing	58

Environmental Effects	
Cleanup Sites	38
Groundwater Threats	62
Hazardous Waste	96
Impaired Waters	0
Solid Waste	53

Sensitive Populations	
Asthma	99
Low Birth Weight	89
Cardiovascular Disease	87

Socioeconomic Factors	
Education	79
Linguistic Isolation	40
Poverty	99
Unemployment	98
Housing Burden	72

Bakersfield-Area Census Tracts



Census Tract: 6029001500
(Population: 2,586)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	95
Pollution Burden Percentile	69
Population Characteristics Percentile	100

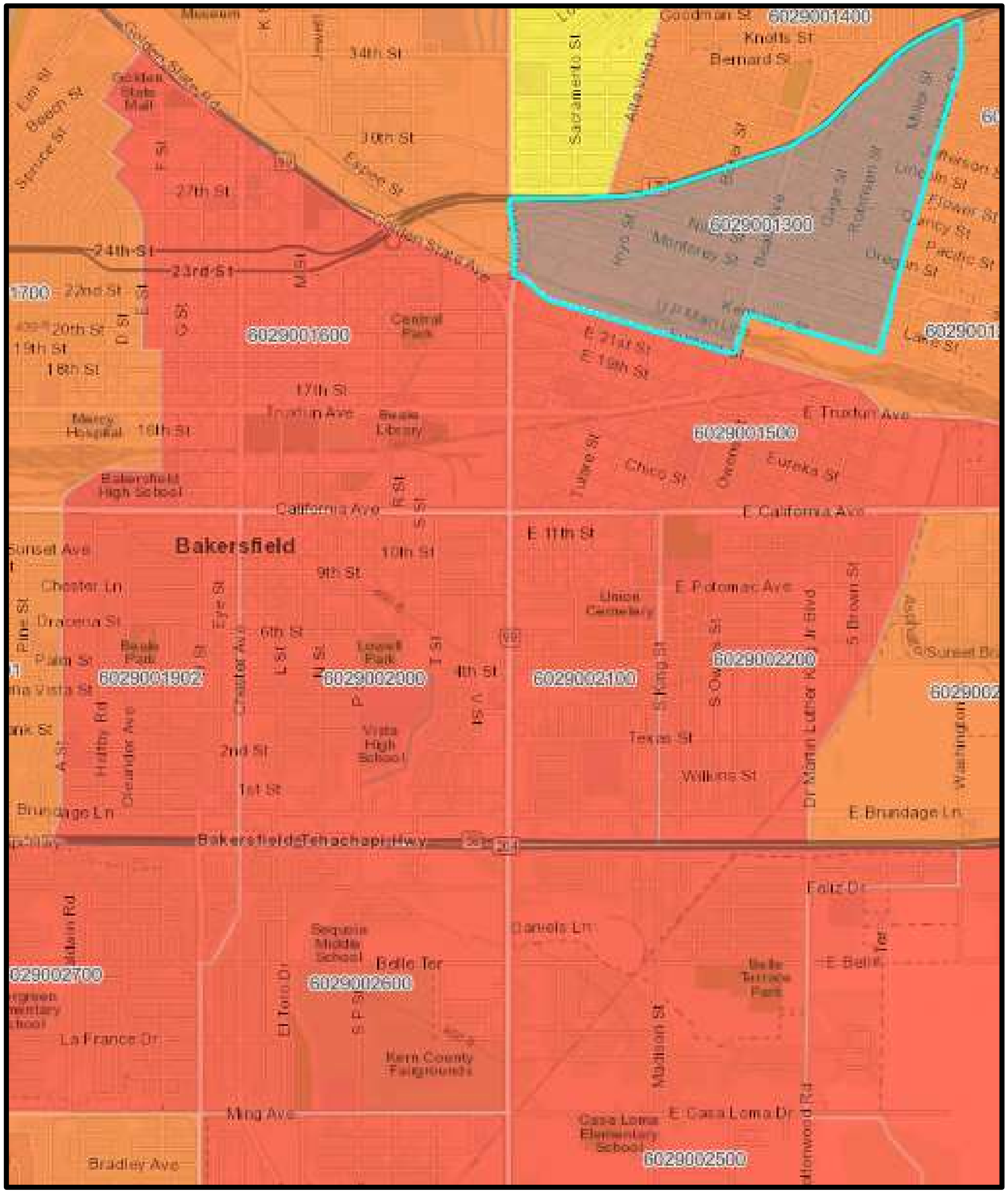
Exposures	
Ozone	94
Particulate Matter 2.5	100
Diesel Particulate Matter	89
Toxic Releases	13
Traffic	21
Pesticides	0
Drinking Water	70
Lead from Housing	98

Environmental Effects	
Cleanup Sites	12
Groundwater Threats	47
Hazardous Waste	78
Impaired Waters	0
Solid Waste	0

Sensitive Populations	
Asthma	94
Low Birth Weight	90
Cardiovascular Disease	82

Socioeconomic Factors	
Education	98
Linguistic Isolation	91
Poverty	100
Unemployment	100
Housing Burden	96

Bakersfield-Area Census Tracts



Census Tract: 6029001300
(Population: 7,114)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	93
Pollution Burden Percentile	62
Population Characteristics Percentile	100

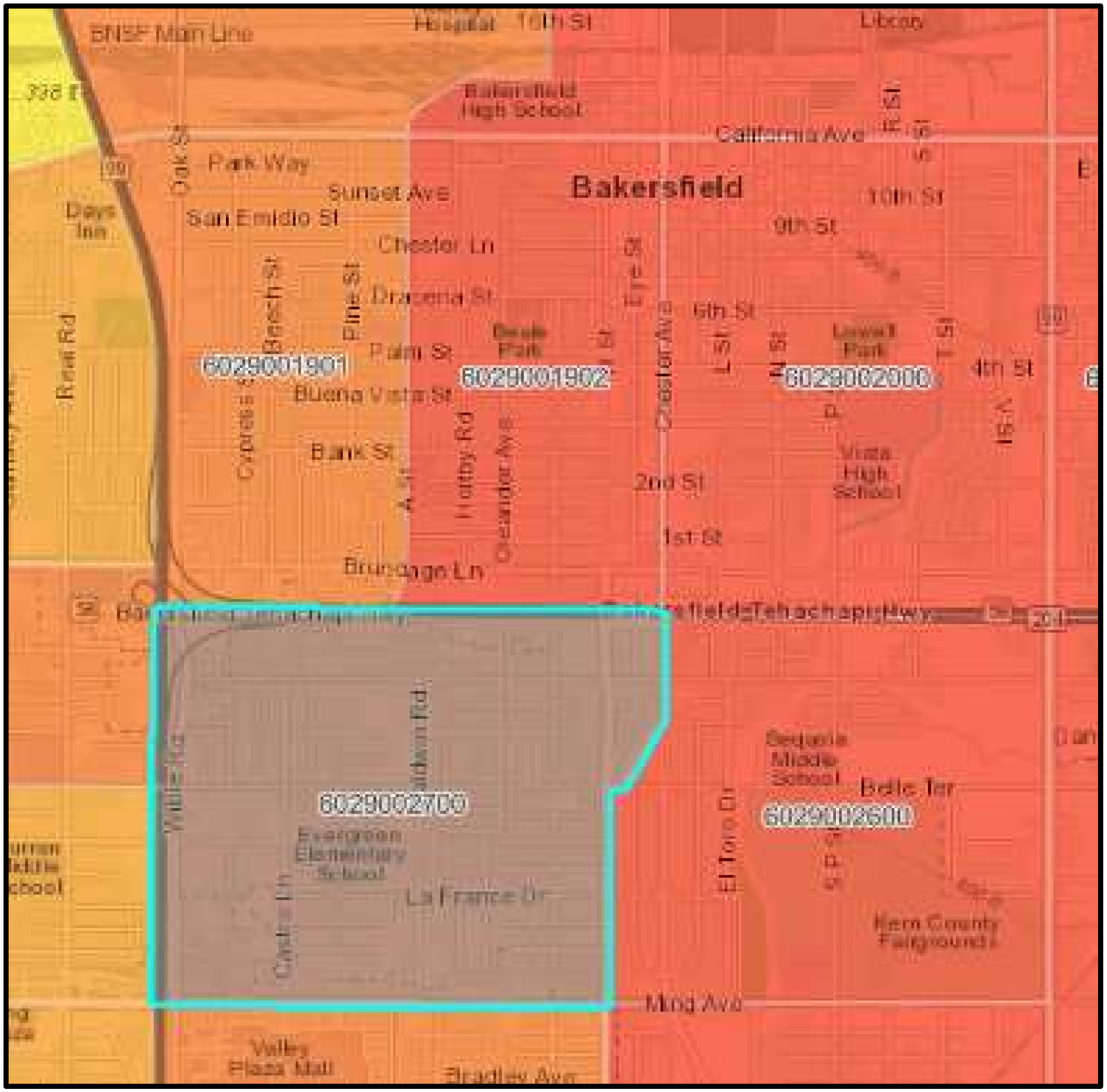
Exposures	
Ozone	94
Particulate Matter 2.5	100
Diesel Particulate Matter	84
Toxic Releases	12
Traffic	11
Pesticides	0
Drinking Water	70
Lead from Housing	91

Environmental Effects	
Cleanup Sites	17
Groundwater Threats	47
Hazardous Waste	62
Impaired Waters	0
Solid Waste	0

Sensitive Populations	
Asthma	97
Low Birth Weight	90
Cardiovascular Disease	93

Socioeconomic Factors	
Education	99
Linguistic Isolation	88
Poverty	100
Unemployment	100
Housing Burden	93

Bakersfield-Area Census Tracts



Census Tract: 6029002700
(Population: 5,903)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	91
Pollution Burden Percentile	78
Population Characteristics Percentile	92

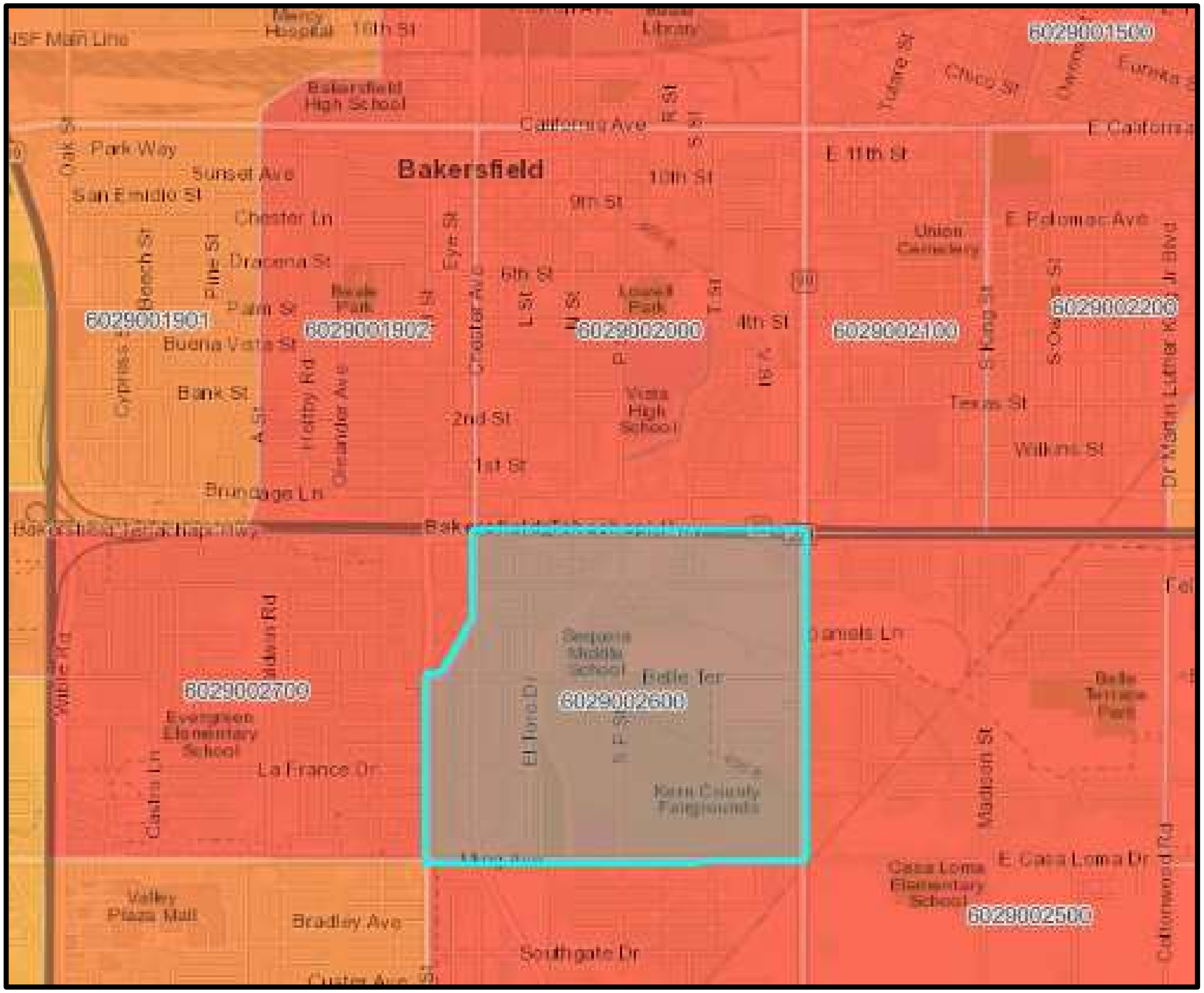
Exposures	
Ozone	94
Particulate Matter 2.5	100
Diesel Particulate Matter	79
Toxic Releases	16
Traffic	67
Pesticides	0
Drinking Water	70
Lead from Housing	93

Environmental Effects	
Cleanup Sites	75
Groundwater Threats	0
Hazardous Waste	71
Impaired Waters	0
Solid Waste	0

Sensitive Populations	
Asthma	97
Low Birth Weight	32
Cardiovascular Disease	97

Socioeconomic Factors	
Education	90
Linguistic Isolation	71
Poverty	91
Unemployment	91
Housing Burden	75

Bakersfield-Area Census Tracts



Census Tract: 6029002600
(Population: 3,477)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	95
Pollution Burden Percentile	84
Population Characteristics Percentile	96

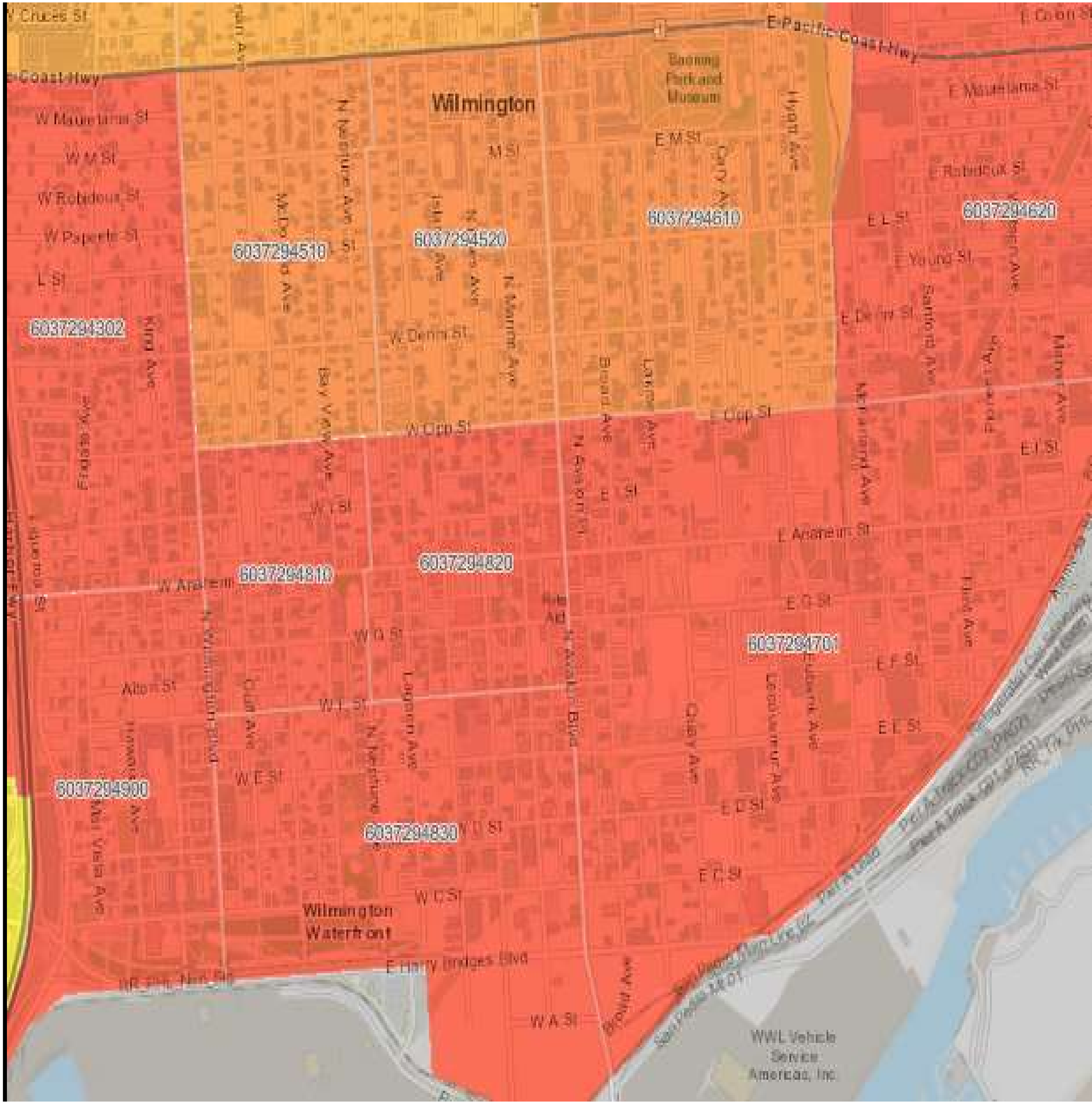
Exposures	
Ozone	94
Particulate Matter 2.5	100
Diesel Particulate Matter	33
Toxic Releases	15
Traffic	43
Pesticides	0
Drinking Water	70
Lead from Housing	96

Environmental Effects	
Cleanup Sites	90
Groundwater Threats	60
Hazardous Waste	72
Impaired Waters	0
Solid Waste	53

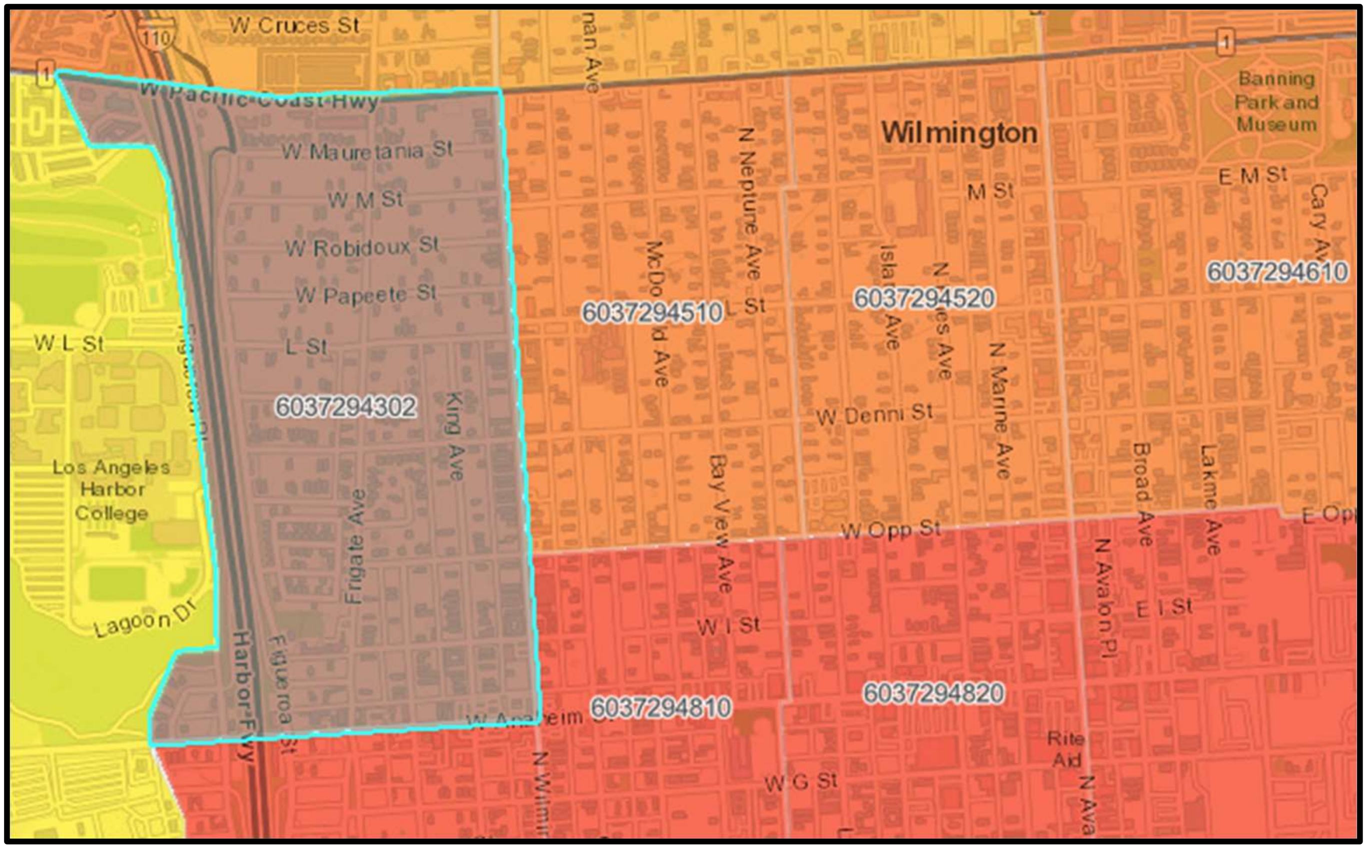
Sensitive Populations	
Asthma	91
Low Birth Weight	85
Cardiovascular Disease	85

Socioeconomic Factors	
Education	83
Linguistic Isolation	59
Poverty	91
Unemployment	96
Housing Burden	72

Los Angeles - Wilmington Area Census Tracts



Los Angeles - Wilmington Area Census Tracts



Census Tract: 6037294302
(Population: 4,382)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	91
Pollution Burden Percentile	87
Population Characteristics Percentile	84

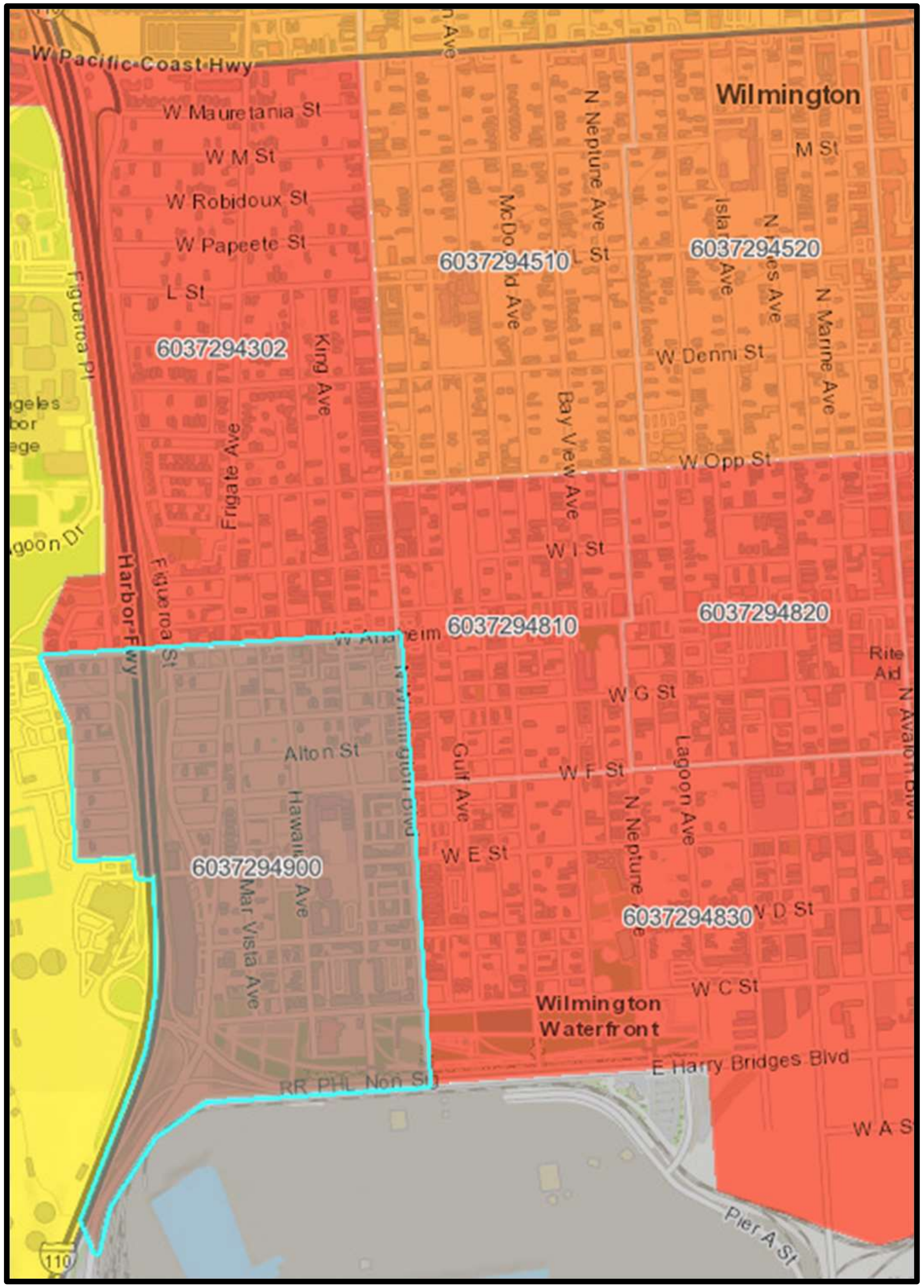
Exposures	
Ozone	21
Particulate Matter 2.5	68
Diesel Particulate Matter	98
Toxic Releases	97
Traffic	83
Pesticides	0
Drinking Water	42
Lead from Housing	86

Environmental Effects	
Cleanup Sites	23
Groundwater Threats	60
Hazardous Waste	80
Impaired Waters	83
Solid Waste	0

Sensitive Populations	
Asthma	82
Low Birth Weight	45
Cardiovascular Disease	92

Socioeconomic Factors	
Education	95
Linguistic Isolation	85
Poverty	72
Unemployment	34
Housing Burden	80

Los Angeles – Wilmington Area Census Tracts



Census Tract: 6037294900
(Population: 3,853)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	96
Pollution Burden Percentile	92
Population Characteristics Percentile	92

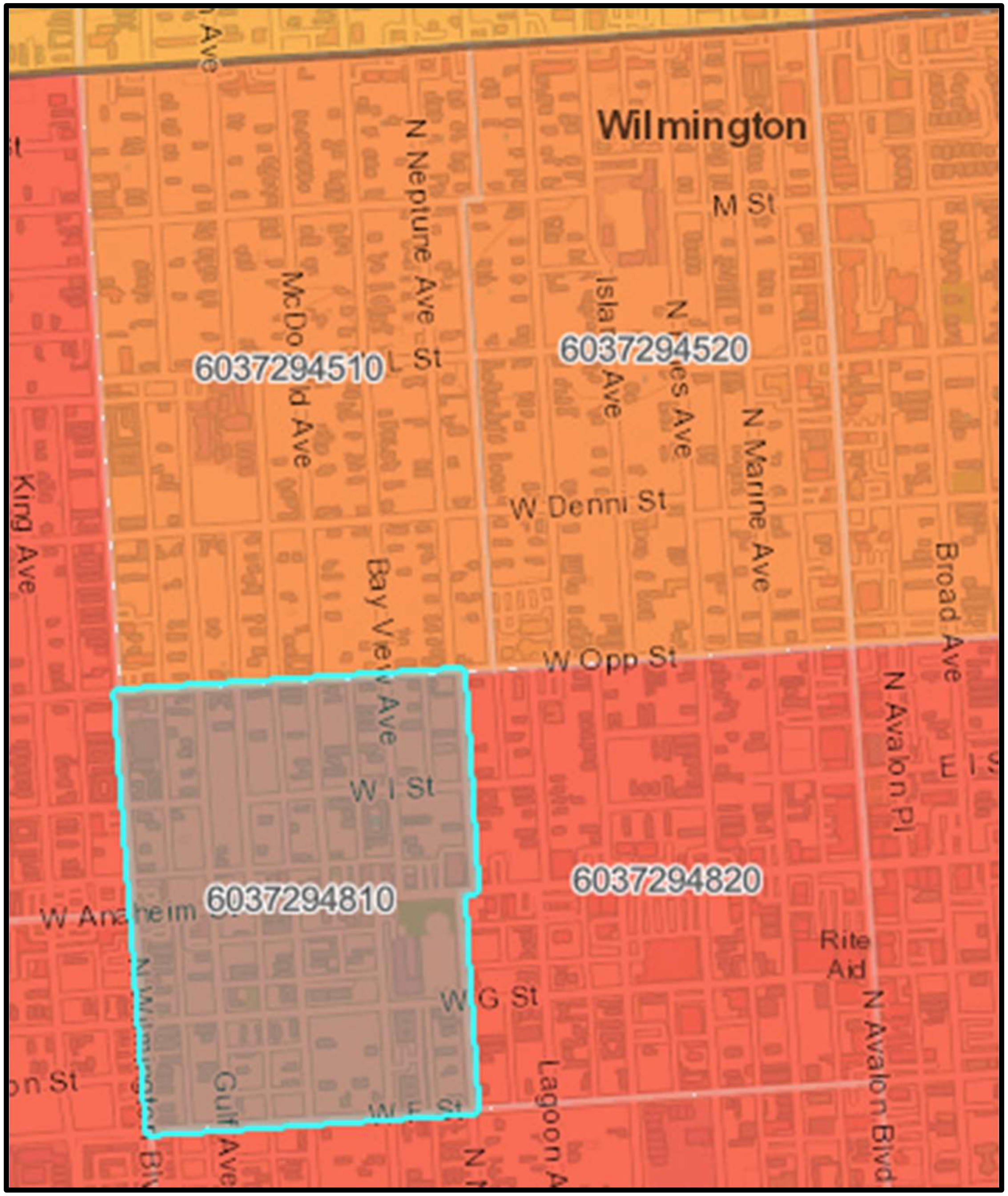
Exposures	
Ozone	18
Particulate Matter 2.5	70
Diesel Particulate Matter	100
Toxic Releases	97
Traffic	76
Pesticides	0
Drinking Water	42
Lead from Housing	97

Environmental Effects	
Cleanup Sites	51
Groundwater Threats	55
Hazardous Waste	84
Impaired Waters	95
Solid Waste	10

Sensitive Populations	
Asthma	81
Low Birth Weight	73
Cardiovascular Disease	89

Socioeconomic Factors	
Education	97
Linguistic Isolation	91
Poverty	93
Unemployment	38
Housing Burden	72

Los Angeles - Wilmington Area Census Tracts



Census Tract: 6037294810
(Population: 4,278)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	91
Pollution Burden Percentile	73
Population Characteristics Percentile	94

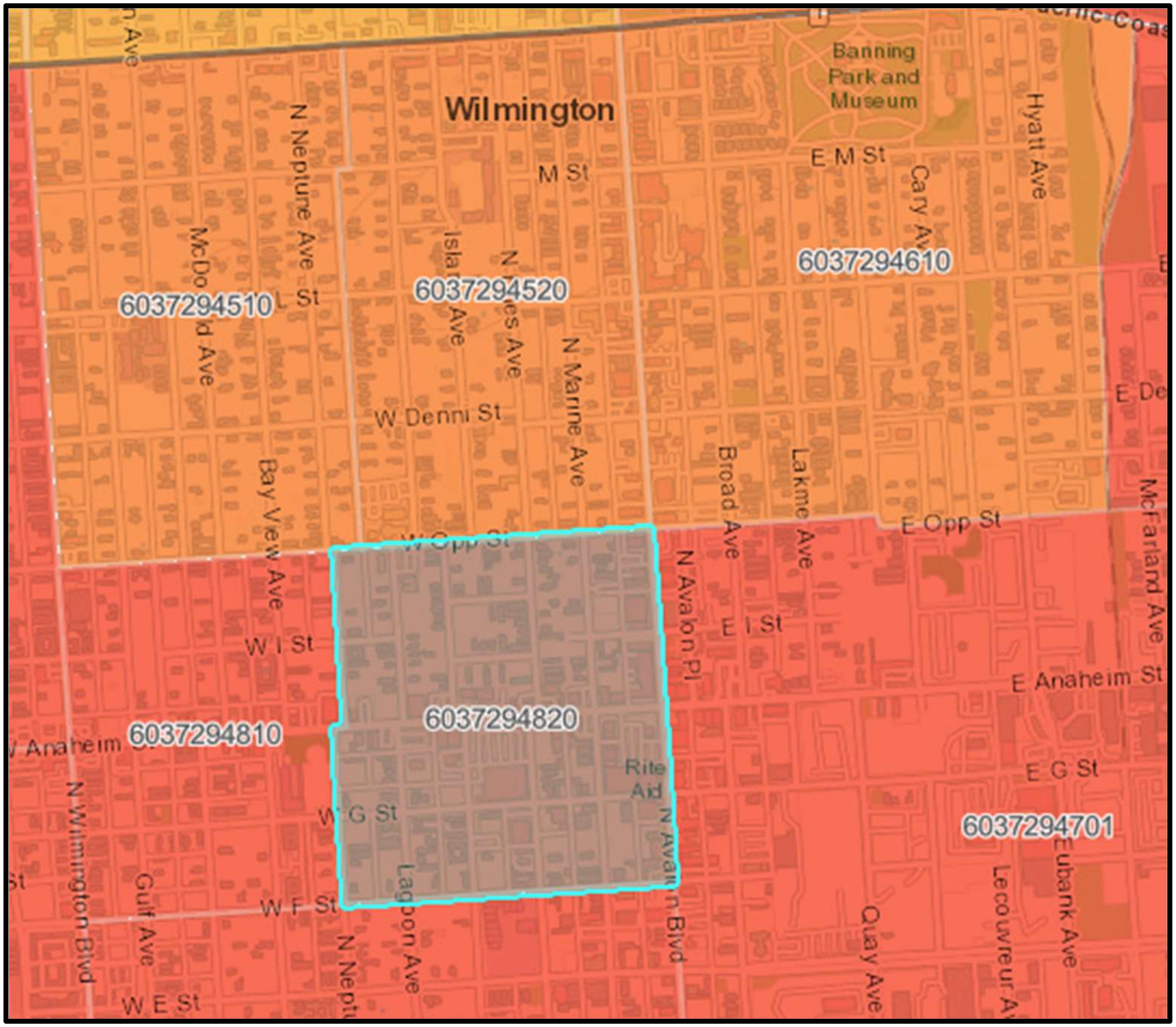
Exposures	
Ozone	18
Particulate Matter 2.5	67
Diesel Particulate Matter	100
Toxic Releases	97
Traffic	29
Pesticides	0
Drinking Water	42
Lead from Housing	86

Environmental Effects	
Cleanup Sites	44
Groundwater Threats	45
Hazardous Waste	56
Impaired Waters	72
Solid Waste	0

Sensitive Populations	
Asthma	83
Low Birth Weight	56
Cardiovascular Disease	93

Socioeconomic Factors	
Education	98
Linguistic Isolation	94
Poverty	95
Unemployment	55
Housing Burden	88

Los Angeles - Wilmington Area Census Tracts



Census Tract: 6037294820
(Population: 3,473)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	95
Pollution Burden Percentile	81
Population Characteristics Percentile	97

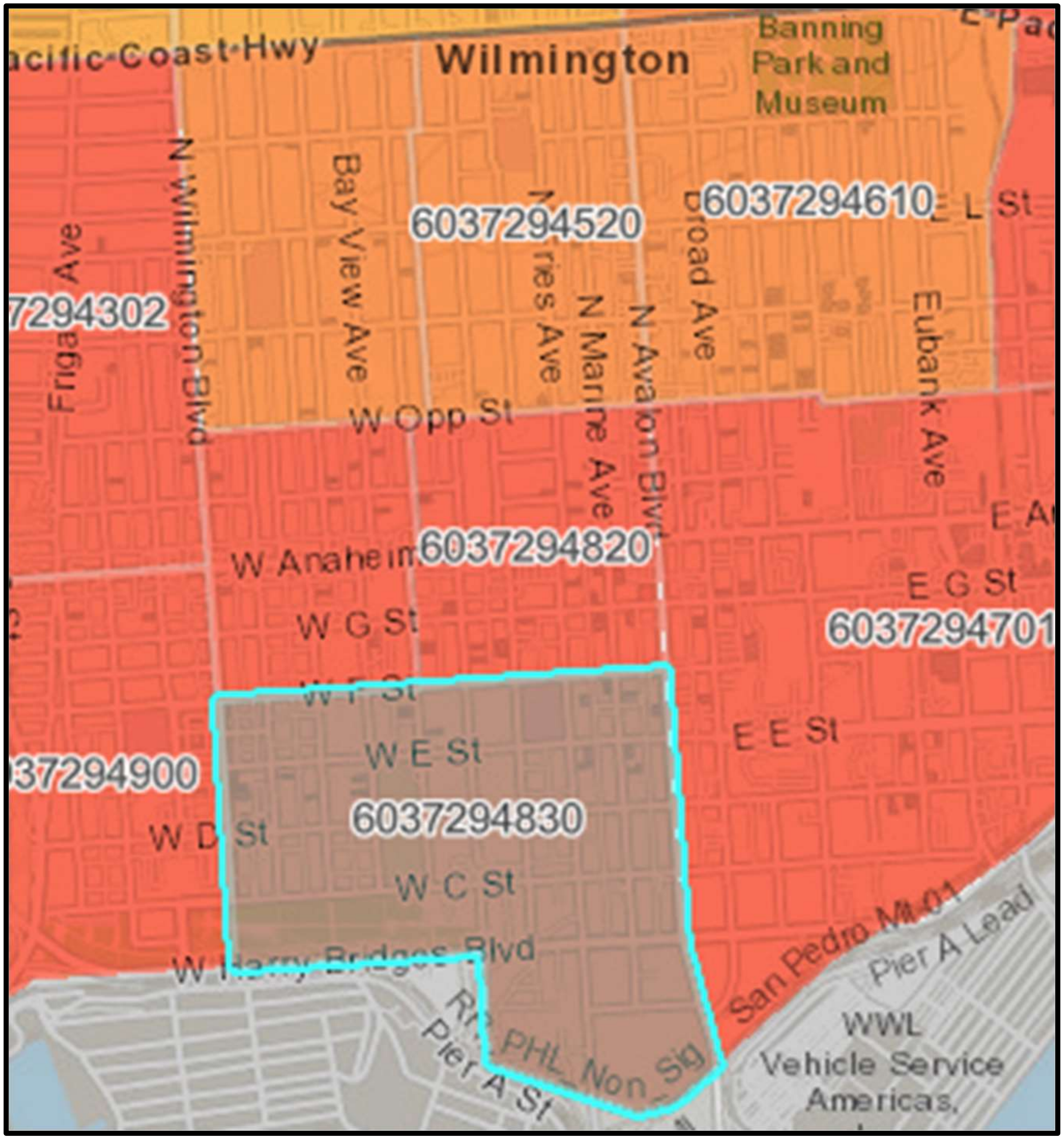
Exposures	
Ozone	18
Particulate Matter 2.5	67
Diesel Particulate Matter	99
Toxic Releases	97
Traffic	24
Pesticides	0
Drinking Water	42
Lead from Housing	92

Environmental Effects	
Cleanup Sites	72
Groundwater Threats	76
Hazardous Waste	63
Impaired Waters	0
Solid Waste	53

Sensitive Populations	
Asthma	83
Low Birth Weight	73
Cardiovascular Disease	93

Socioeconomic Factors	
Education	100
Linguistic Isolation	97
Poverty	97
Unemployment	91
Housing Burden	58

Los Angeles - Wilmington Area Census Tracts



Census Tract: 6037294830 (Population: 4,134)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	98
Pollution Burden Percentile	91
Population Characteristics Percentile	96

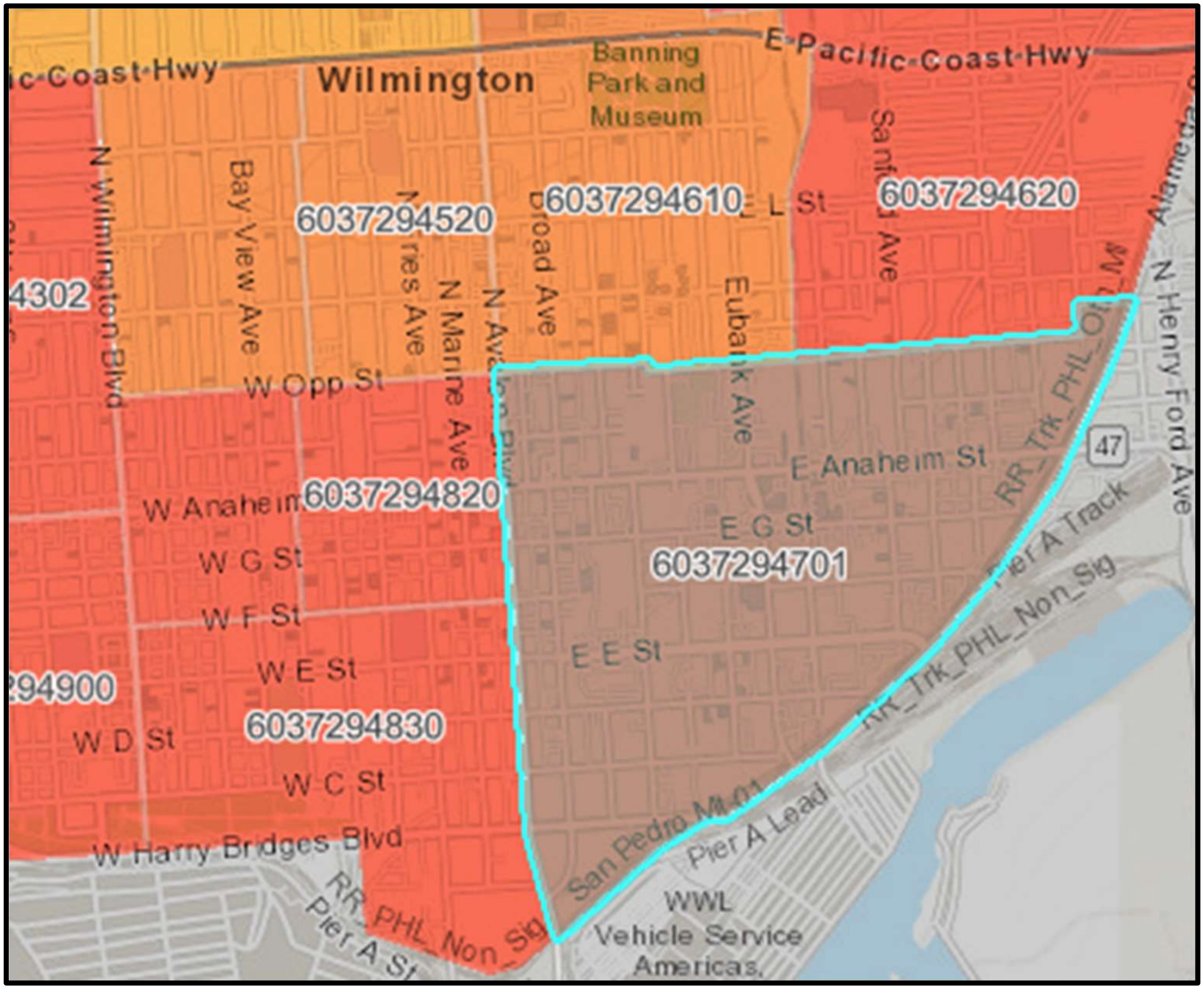
Exposures	
Ozone	17
Particulate Matter 2.5	69
Diesel Particulate Matter	100
Toxic Releases	97
Traffic	5
Pesticides	0
Drinking Water	42
Lead from Housing	90

Environmental Effects	
Cleanup Sites	95
Groundwater Threats	69
Hazardous Waste	85
Impaired Waters	72
Solid Waste	61

Sensitive Populations	
Asthma	83
Low Birth Weight	82
Cardiovascular Disease	93

Socioeconomic Factors	
Education	96
Linguistic Isolation	88
Poverty	91
Unemployment	48
Housing Burden	93

Los Angeles – Wilmington Area Census Tracts



Census Tract: 6037294701
(Population: 3,099)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	99
Pollution Burden Percentile	98
Population Characteristics Percentile	94

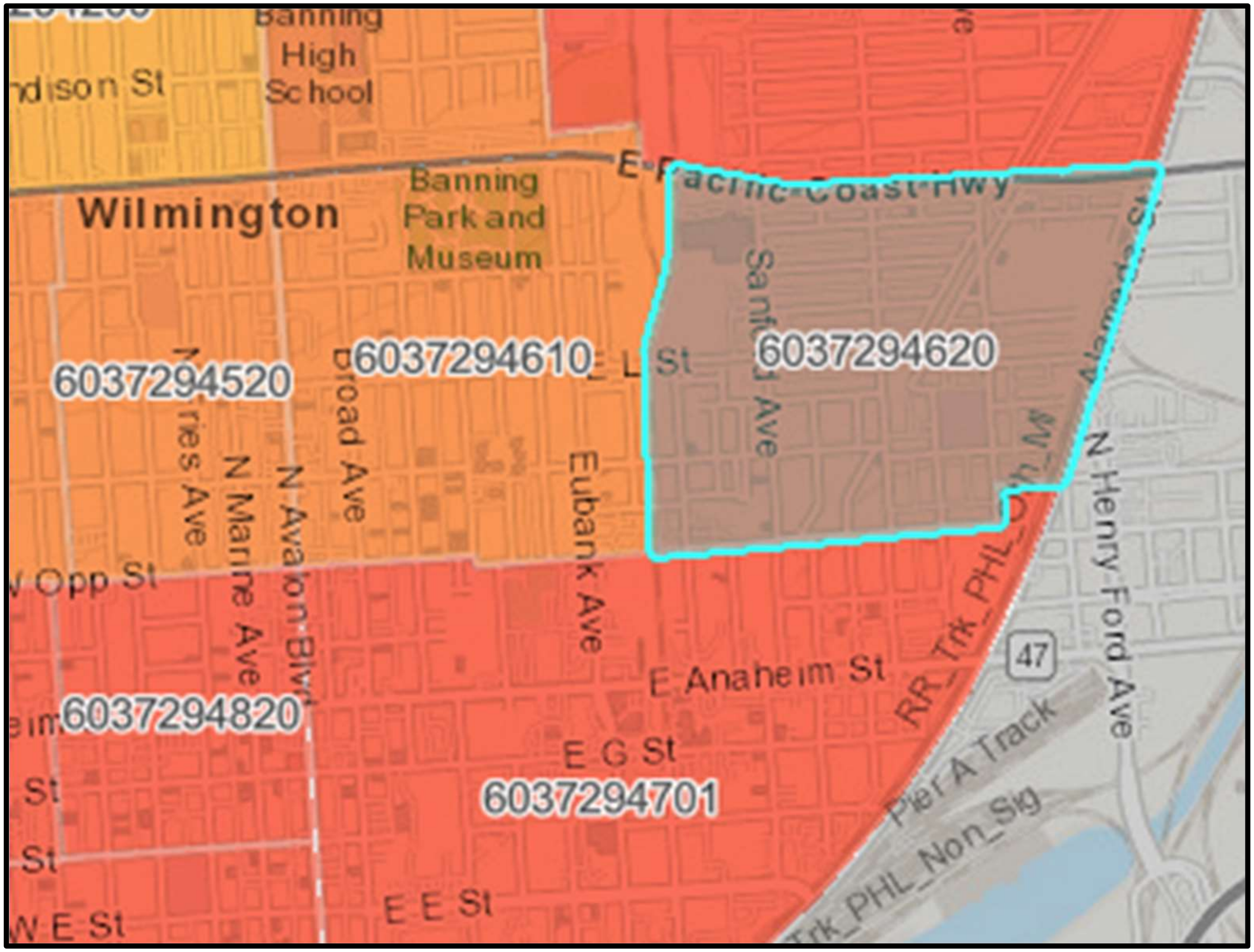
Exposures	
Ozone	18
Particulate Matter 2.5	67
Diesel Particulate Matter	99
Toxic Releases	97
Traffic	31
Pesticides	0
Drinking Water	42
Lead from Housing	90

Environmental Effects	
Cleanup Sites	95
Groundwater Threats	93
Hazardous Waste	97
Impaired Waters	96
Solid Waste	98

Sensitive Populations	
Asthma	83
Low Birth Weight	64
Cardiovascular Disease	93

Socioeconomic Factors	
Education	97
Linguistic Isolation	92
Poverty	91
Unemployment	43
Housing Burden	91

Los Angeles – Wilmington Area Census Tracts



Census Tract: 6037294620
(Population: 4,683)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	91
Pollution Burden Percentile	95
Population Characteristics Percentile	74

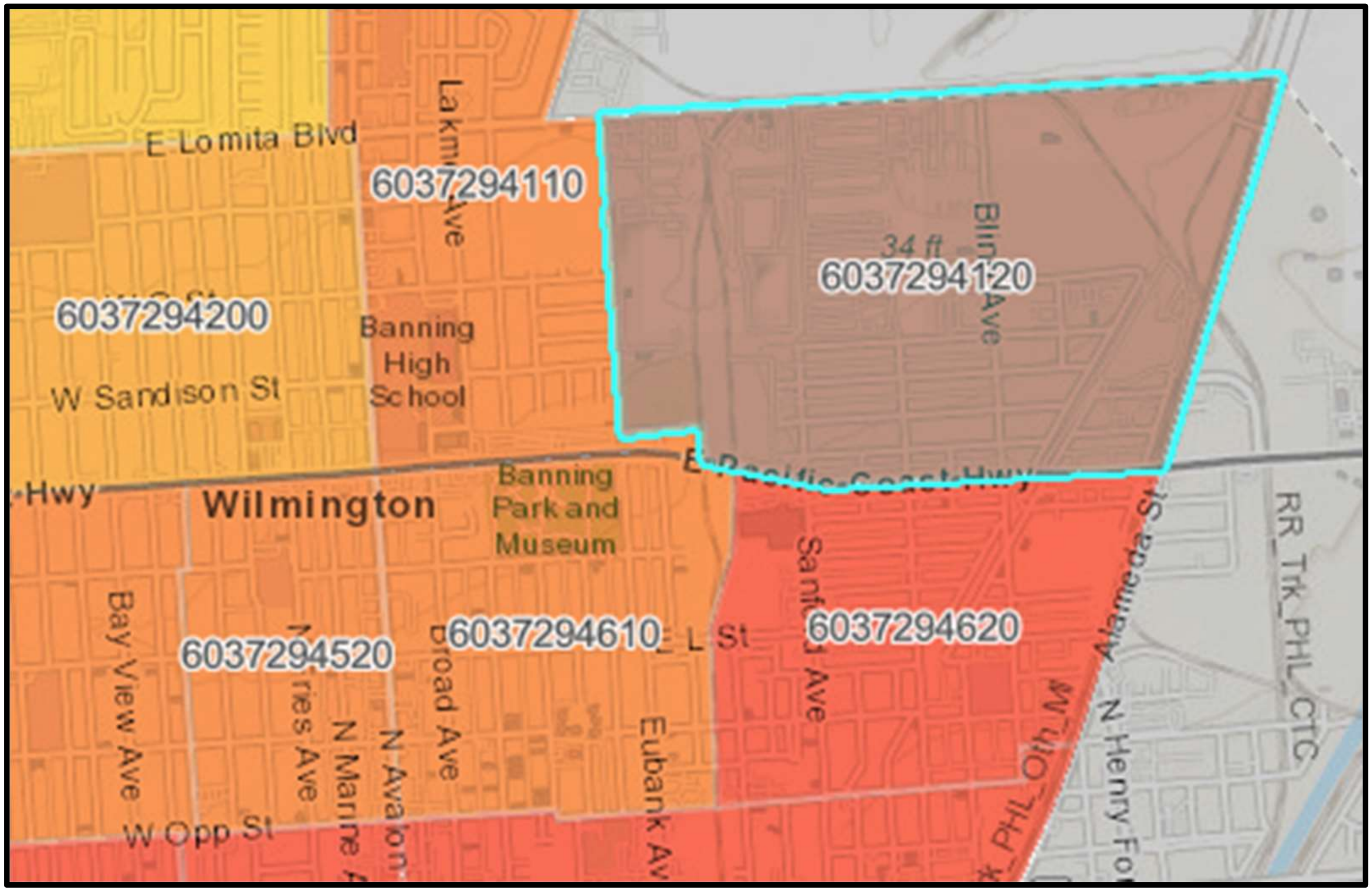
Exposures	
Ozone	21
Particulate Matter 2.5	66
Diesel Particulate Matter	45
Toxic Releases	98
Traffic	59
Pesticides	0
Drinking Water	42
Lead from Housing	93

Environmental Effects	
Cleanup Sites	55
Groundwater Threats	78
Hazardous Waste	100
Impaired Waters	96
Solid Waste	93

Sensitive Populations	
Asthma	83
Low Birth Weight	21
Cardiovascular Disease	93

Socioeconomic Factors	
Education	91
Linguistic Isolation	23
Poverty	85
Unemployment	75
Housing Burden	58

Los Angeles - Wilmington Area Census Tracts



Census Tract: 6037294120
(Population: 2,687)

Zoom to

Overall Percentiles	
CalEnviroScreen 4.0 Percentile	97
Pollution Burden Percentile	93
Population Characteristics Percentile	93

Exposures	
Ozone	21
Particulate Matter 2.5	68
Diesel Particulate Matter	84
Toxic Releases	99
Traffic	66
Pesticides	21
Drinking Water	42
Lead from Housing	95

Environmental Effects	
Cleanup Sites	59
Groundwater Threats	56
Hazardous Waste	97
Impaired Waters	0
Solid Waste	90

Sensitive Populations	
Asthma	83
Low Birth Weight	62
Cardiovascular Disease	93

Socioeconomic Factors	
Education	96
Linguistic Isolation	60
Poverty	78
Unemployment	80
Housing Burden	94

CALIFORNIA

STATE OIL AND GAS SUPERVISOR

ANNUAL REPORT 2020

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Commencing in January 2020, the Division of Oil, Gas, and Geothermal Resources (DOGGR) became the California Geologic Energy Management (CalGEM) Division and commenced work to implement major policy and programmatic changes. That work included a renewed mission that prioritizes protecting public health, safety, and the environment in its oversight of the oil, natural gas, and geothermal industries, while working to help California achieve its climate change and clean energy goals.

This report is developed pursuant to Public Resources Code (PRC) section 3108 which requires a report to be produced each year covering key oil and gas statistics, CalGEM's financial information, and other data the State Oil and Gas Supervisor (Supervisor) deems advisable to include. This report provides the following required data per PRC section 3108:

1. The total amounts of oil and gas produced in each county in the state during the previous calendar year.

2. The total cost of the division for the previous fiscal year.

3. The total amount delinquent and uncollected from any assessments or charges levied pursuant to this chapter.

This report covers calendar year 2020 and fiscal year 2019-2020.

Oil Production

Oil production saw a notable drop in 2020, totaling 148.2 Million Crude Oil Barrel Units (MMbbl) (about 406,227 barrels per day), a decrease of 7 percent from the 2019 total of 159.5 MMbbl (about 436,866 barrels per day). The decrease in oil production was due in large part to two key factors: (1) the drop in oil price, likely as a result of decreased demand for oil during the COVID-19 pandemic, and (2) an ongoing natural decline in production. Statewide oil production has declined to levels not seen for the past 80 years. California oil production peaked in 1985 and continued its decline at an average of 2.2 percent per year.

In 2020, California ranked seventh among the oil producing states, behind Texas, North Dakota, New Mexico, Oklahoma, Colorado, and Alaska, according to the U.S. Energy Information Administration.

Natural Gas Production

Net natural gas production decreased in 2020, dropping about 10 percent from 2019 levels. Associated gas production decreased from 149 billion cubic feet in 2019 to 136.6

billion cubic feet in 2020. Non-associated gas production decreased significantly from 16.6 billion cubic feet in 2019 to 12.6 billion cubic feet in 2020 – a 24 percent decrease in production. The Elk Hills oil field continued as the largest field producing associated gas in California, while the Rio Vista gas field remained the largest field producing non-associated gas (the term “non-associated gas,” used throughout this report, refers to natural gas produced from a gas-targeted or natural gas well rather than an oil well).

Geothermal Production

California is a worldwide leader in geothermal energy generation and the largest producer of geothermal energy in the United States. According to the California Energy Commission, there are 2,712 megawatts (MW) of electricity coming from 40 geothermal power plants; enough electricity for about 2.7 million residents. In 2020, geothermal energy sources produced 11,345 gigawatt-hours net (GWh), 5.94 percent of the state’s power mix. That is a slight increase in production from 2019, which saw geothermal energy sources produce 10,943 GWh, 5.46 percent of the state’s power mix.

CalGEM supervises the drilling, operation, maintenance, and plugging and abandonment of high and low-temperature geothermal wells, including injection wells for the discovery and production of geothermal resources in such manner as to safeguard life, health, property, and the public welfare, and to encourage maximum economic recovery (Pub. Resources Code, §§ 3700, 3714). CalGEM supports the expansion of geothermal energy production and is currently undertaking an active rulemaking process to update the geothermal regulations and to maximize safety while enabling responsible development of the resource.

Enforcement

The CalGEM Office of Enforcement was created in July 2019 to facilitate the statewide Enforcement program. The Enforcement Program, which has jurisdiction over all of CalGEM’s regulated entities to include oil, gas, and geothermal operators, works to enforce California’s oil and gas laws and regulations and takes action to prevent damage and issue civil penalties as restitution for actual or potential damages to life, health, property, or natural resources.

In 2020, CalGEM’s Office of Enforcement issued 16 enforcement orders, including civil penalty fines of $191,669. The orders issued generally required operators to remediate field violations or otherwise unsafe conditions at their facilities, plug and abandon wells, and/or pay civil penalties.The Supervisor may also issue emergency orders to address a life, health, safety, property, or natural resources concern.

Additionally, in 2020, CalGEM completed 48,488 inspections and issued 1,183 notices of violation (NOVs).

Budget

Program funding for CalGEM is derived, in part, from the oil and gas assessment paid annually by all oil and gas operators pursuant to PRC division 3, chapter 1, article 7.

As provided for in PRC section 3724.5, CalGEM is also partly funded by an annual well fee levied on operators of high-temperature geothermal resource wells and by drilling fees charged to geothermal operators for drilling new wells or re-drilling abandoned wells.

Additionally, as provided for in PRC section 3403.5, CalGEM is partly funded by an annual charge levied upon operators of underground natural gas storage facilities.

CalGEM’s total resources for Fiscal Year (FY) 2019/2020 is $122,984,000 which includes $102,178,000 in assessment fee revenue.

CalGEM’s 2020 Financial Statement can be found at Appendix C.

ORGANIZATIONAL BACKGROUND

CalGEM staff are organized into two major groupings: districts and programs. Districts are geographically based, and the state is divided into the following districts: Southern (Long Beach), Coastal (Orcutt & Ventura), Inland (Bakersfield), and Northern (Sacramento).[1] Districts perform most of the permitting, all the field inspections/activities, and most of the interaction with regulated operators. Programs are based upon program area and their purpose is to set standards for regulatory areas, like Underground Injection Control permitting, coordinate enforcement actions initiated by districts, and provide support to districts to ensure consistency of regulatory application across the various districts.

On October 12, 2019, Governor Gavin Newsom signed Assembly Bill (AB) 1057 (Limon, Chapter 771, Statutes of 2019) into law. The new legislation renamed the California Department of Conservation's Division of Oil, Gas, and Geothermal Resources (DOGGR), a division founded in 1915 with a focus on the development of petroleum resources, to the California Geologic Energy Management Division (CalGEM). Furthermore, AB 1057 elevated CalGEM's focus on public health, safety, environmentalprotection, and advancing the state's clean energy goals.

In addition, AB 1057 charged CalGEM with the following directives:

- Reduce and mitigate greenhouse gas emissions associated with the development of hydrocarbon and geothermal resources in a manner that meets the energy needs of the state;

- Require increased financial assurances from onshore operators if existing assurances are inadequate; and

- Mandate additional documentation from operators when ownership of wells or facilities changes, such as proof of sale and lease agreements.

The name change became effective on January 1, 2020, and CalGEM became the steward of California's geologic energy resources and the repository of more than 170,000 well records, production and injection statistics, well logs, and field maps. CalGEM will continue ensuring compliance with California's laws and regulations, while increasing California's health, safety, and environmental efforts.

[1] In mid-2021, CalGEM reorganized its districts from four to three – Coastal and Northern Districts merged to form a new Northern District. The change brings the new Northern District into parity with the other two Districts, Southern and Inland, in terms of staff size and leadership structure.

2020 CALIFORNIA OIL AND GAS PRODUCTION

OIL PRODUCTION

State Oil Production (MMbbl per year)*

Without Federal OCS (Outer Continental Shelf) Production

Year	2020	2019	2018	2017	2016
State Onshore	139.3	152.6	156.4	163.2	174.1
State Offshore	9.0	6.9	7.7	11.3	12.3
Total	148.3	159.5	164.1	174.5	186.4

*Million Crude Oil Barrel Units (MMbbl)

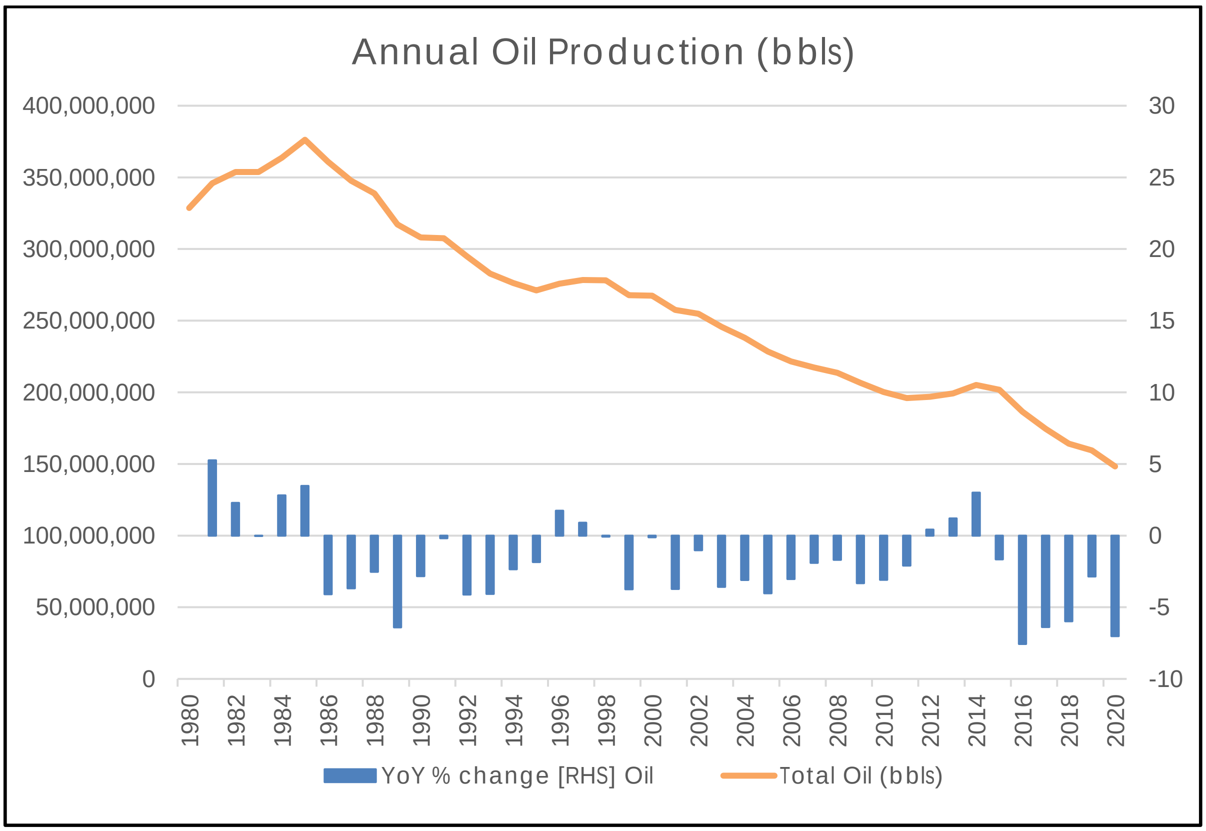


Figure 1: California oil production in barrels per year in annual frequency. Yearly oil production peaked in 1985 at 376,255,669 bbl/year, representing a little over 1 million bbl/day. The blue bars represent the year-over-year percentage change in production, with the axis on the right-hand side [RHS]. Since peaking in 1985, year-over-year oil production has increased only during 5 years: 1996, 1997, 2012, 2013 and 2014. The average decline rate since the peak in 1985 is 2 percent with an acceleration in the decline since 2015.

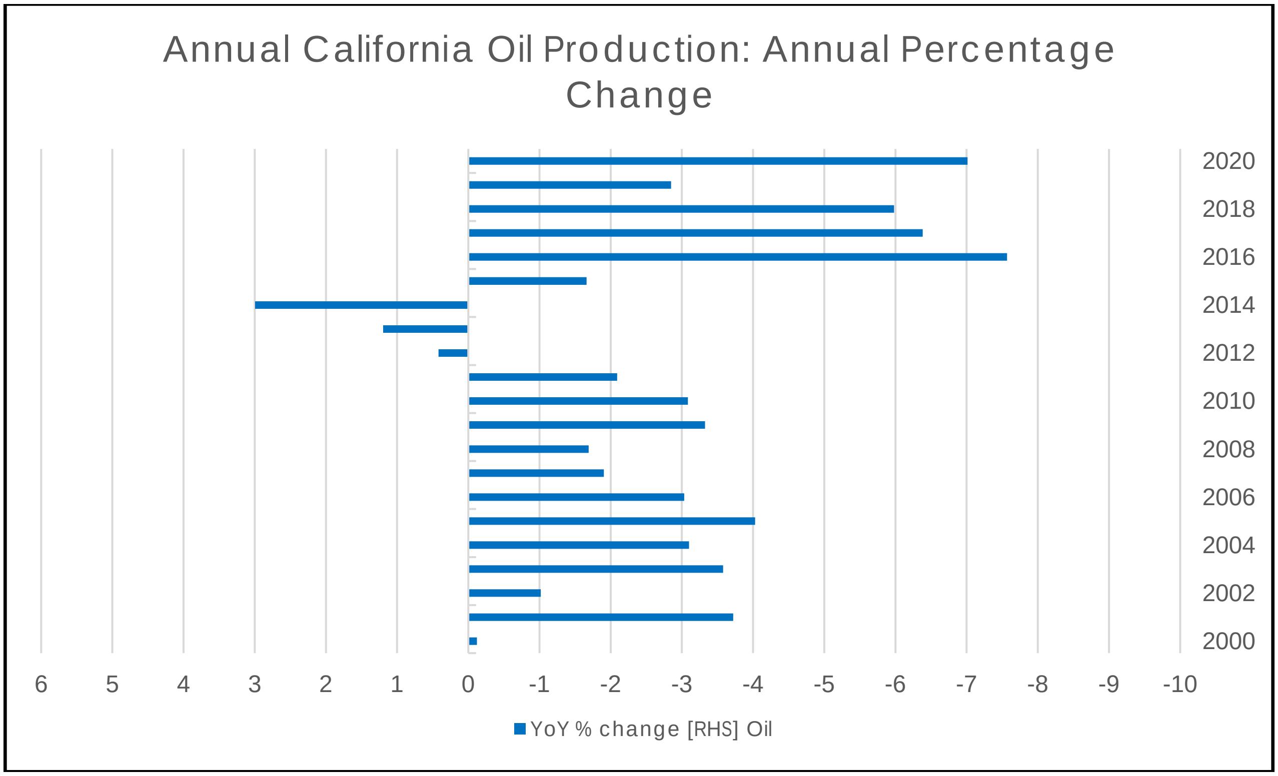


Figure 2: Impact of the COVID-19 Pandemic on California oil production with annual change in oil production.

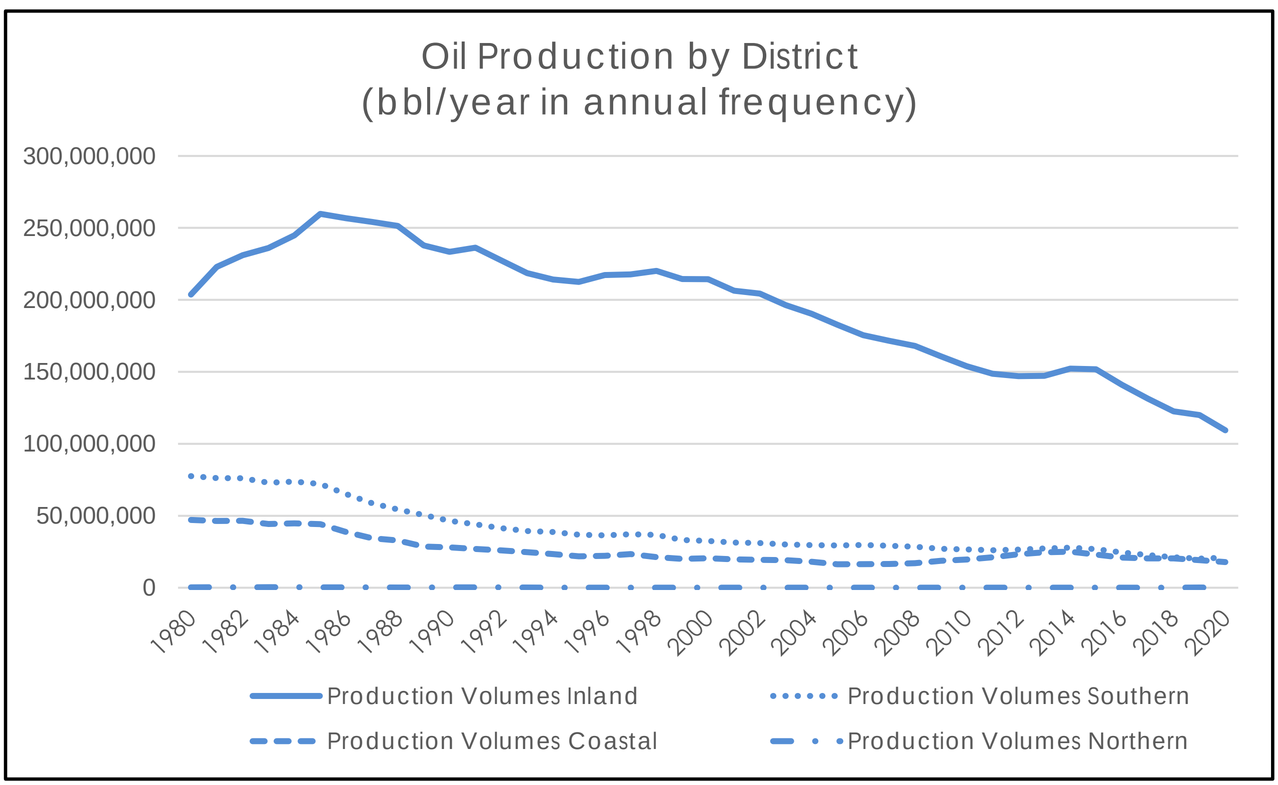


Figure 3: Oil production by district in barrels per year in annual frequency. Notice Inland district annual oil production peaked in 1985 at 259,761,869 bbl/month. Oil production in Northern district is minimal and represented an average of 74,079 bbl/year in 2020.

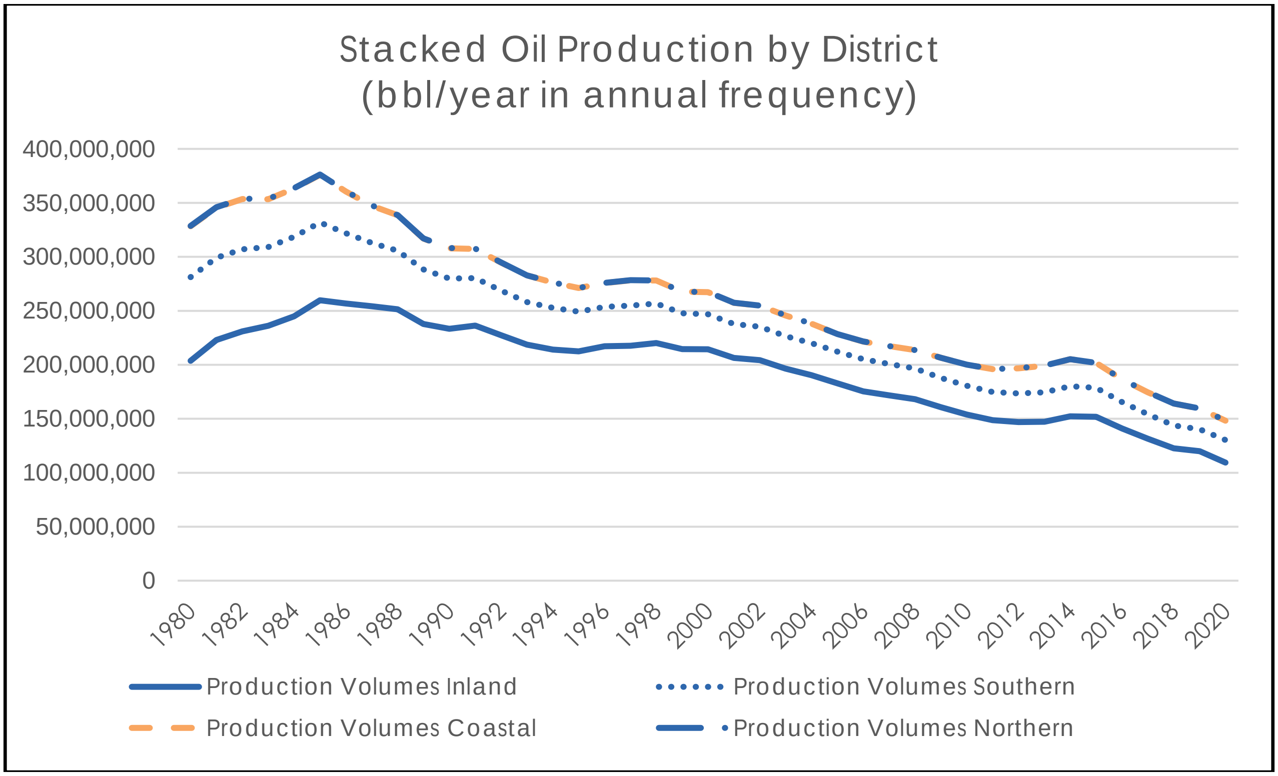


Figure 4: Stacked oil production by district in barrels per year in annual frequency. Notice the peak in annual production in 1985 at 376,255,669 bbl/year.

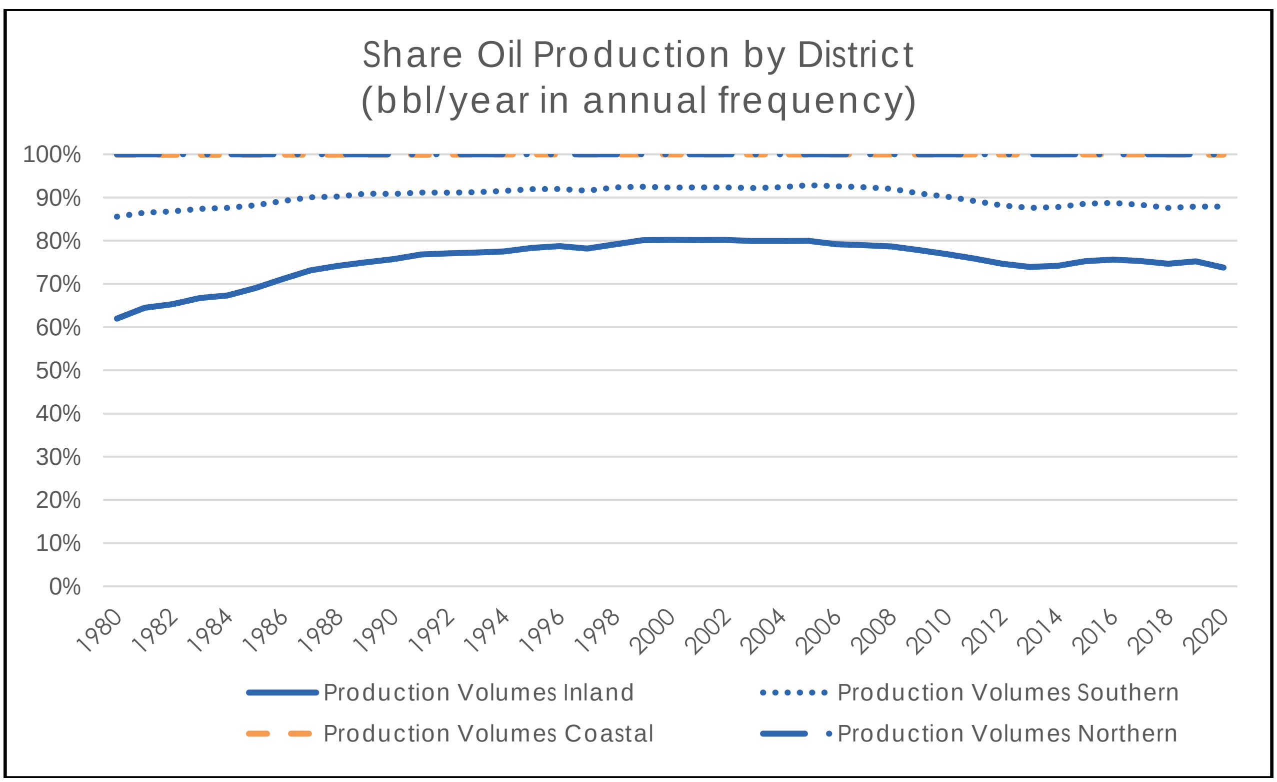


Figure 5: Share of oil production by district in barrels per year in annual frequency. Notice Inland district monthly production increased from about 60 percent in 1980 to about 80 percent by 2000. The share of oil production from Southern district decreased the most between 1980 and 2020.

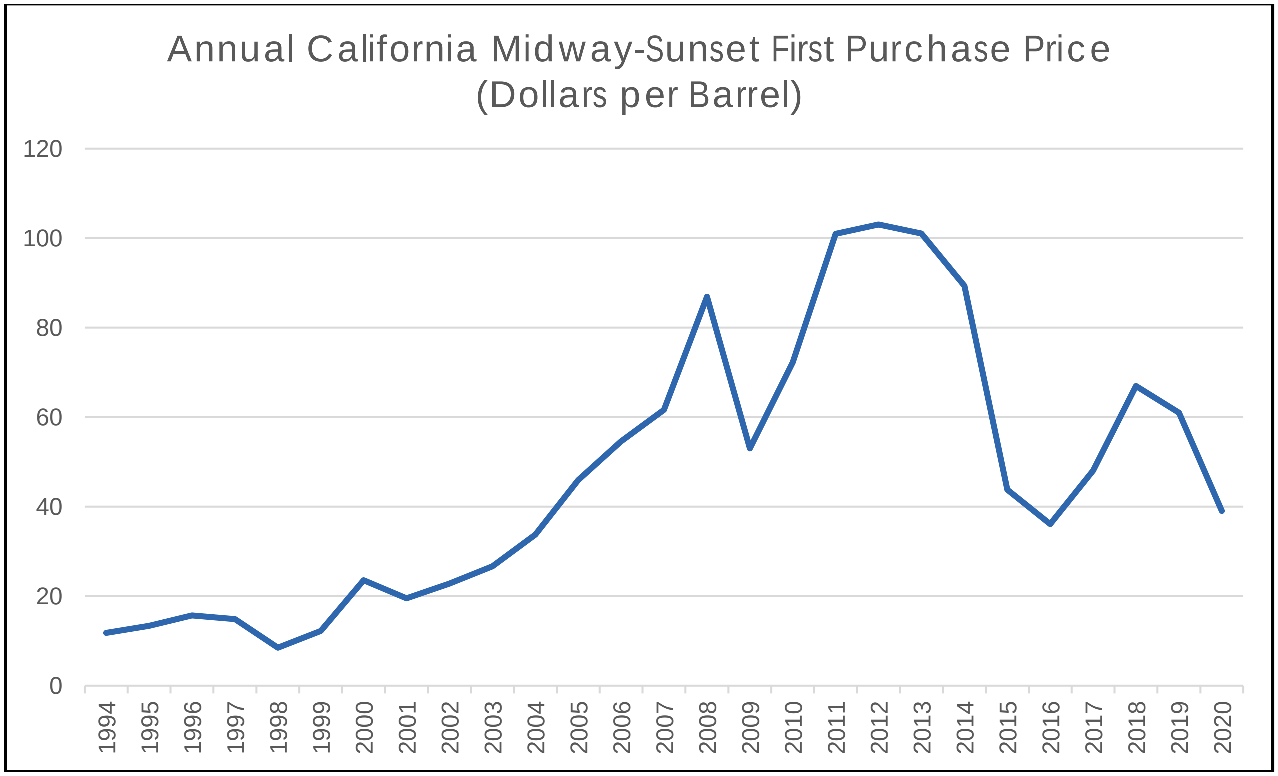


Figure 6: Annual Midway-Sunset Oil Price (note that the "Midway-Sunset" price, or oil price, is used throughout this document to refer to the average price of oil in California). Source: U.S. Energy Information Administration (EIA)
https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F005006143&f=A

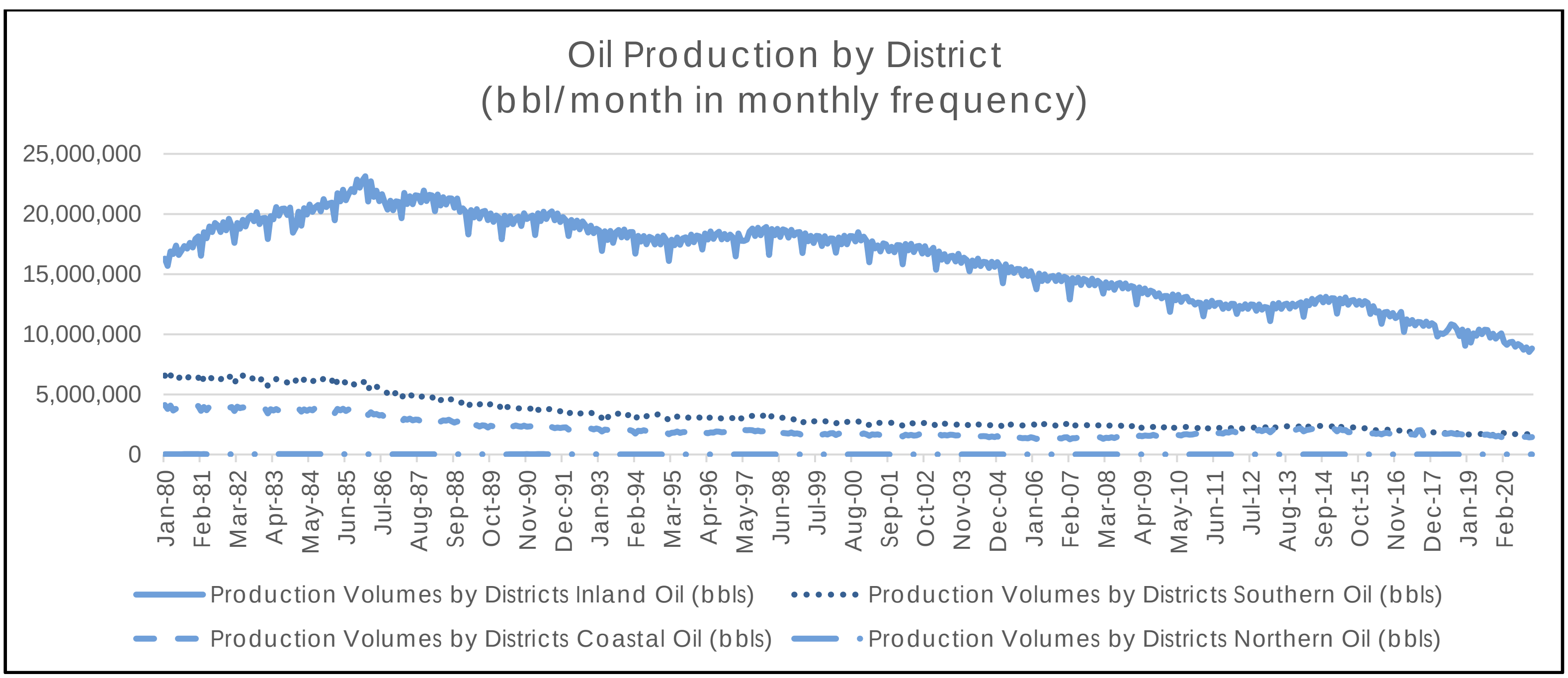


Figure 7: Oil production by district in barrels per month in monthly frequency. Notice Inland district monthly production peaked in January 1986 at 23,187,838 bbl/month. Oil production in Northern district is minimal andrepresented an average of 6,173 bbl/month in 2020.

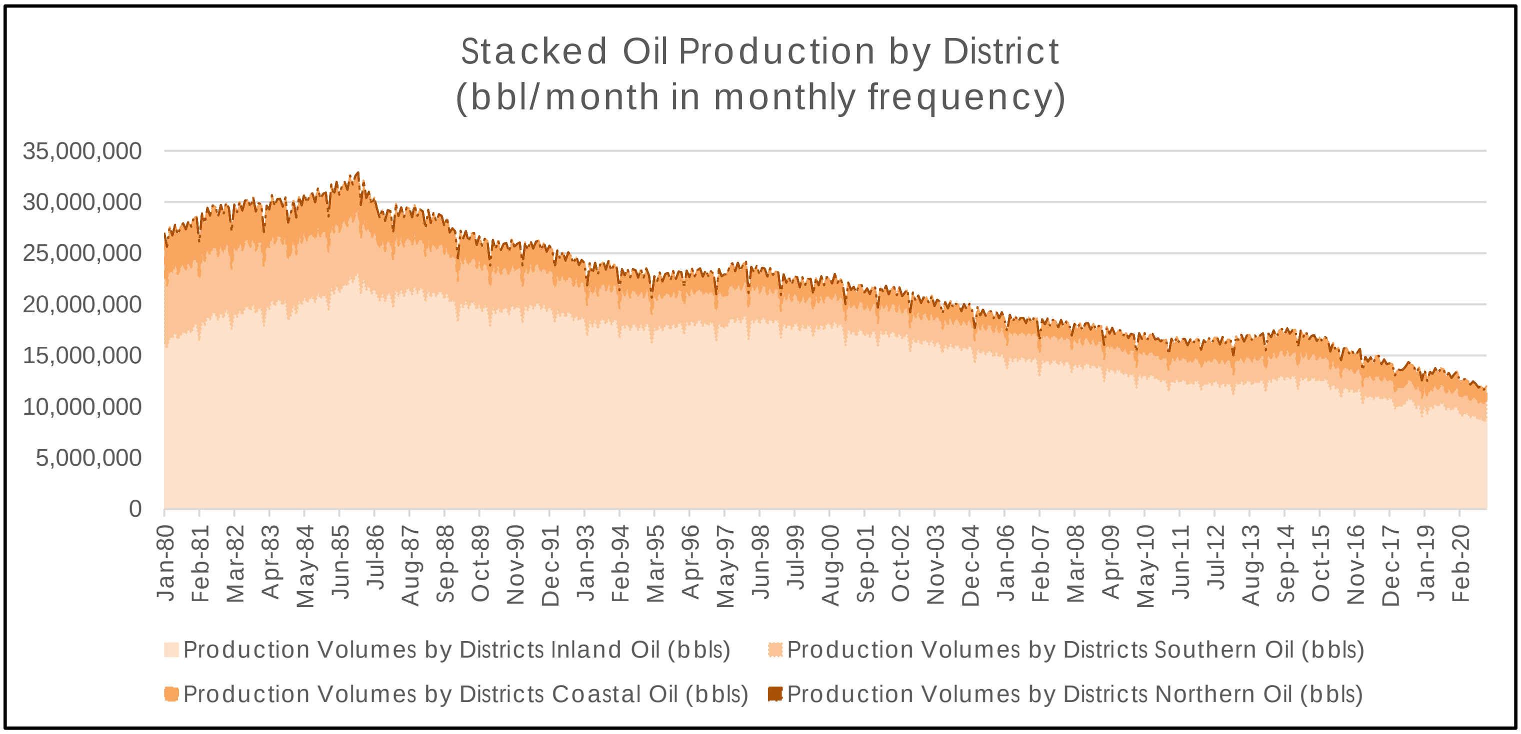


Figure 8: Stacked oil production by district in barrels per month in monthly frequency. Notice the peak in monthly production in January 1986 at 32,895,831 bbl/month.

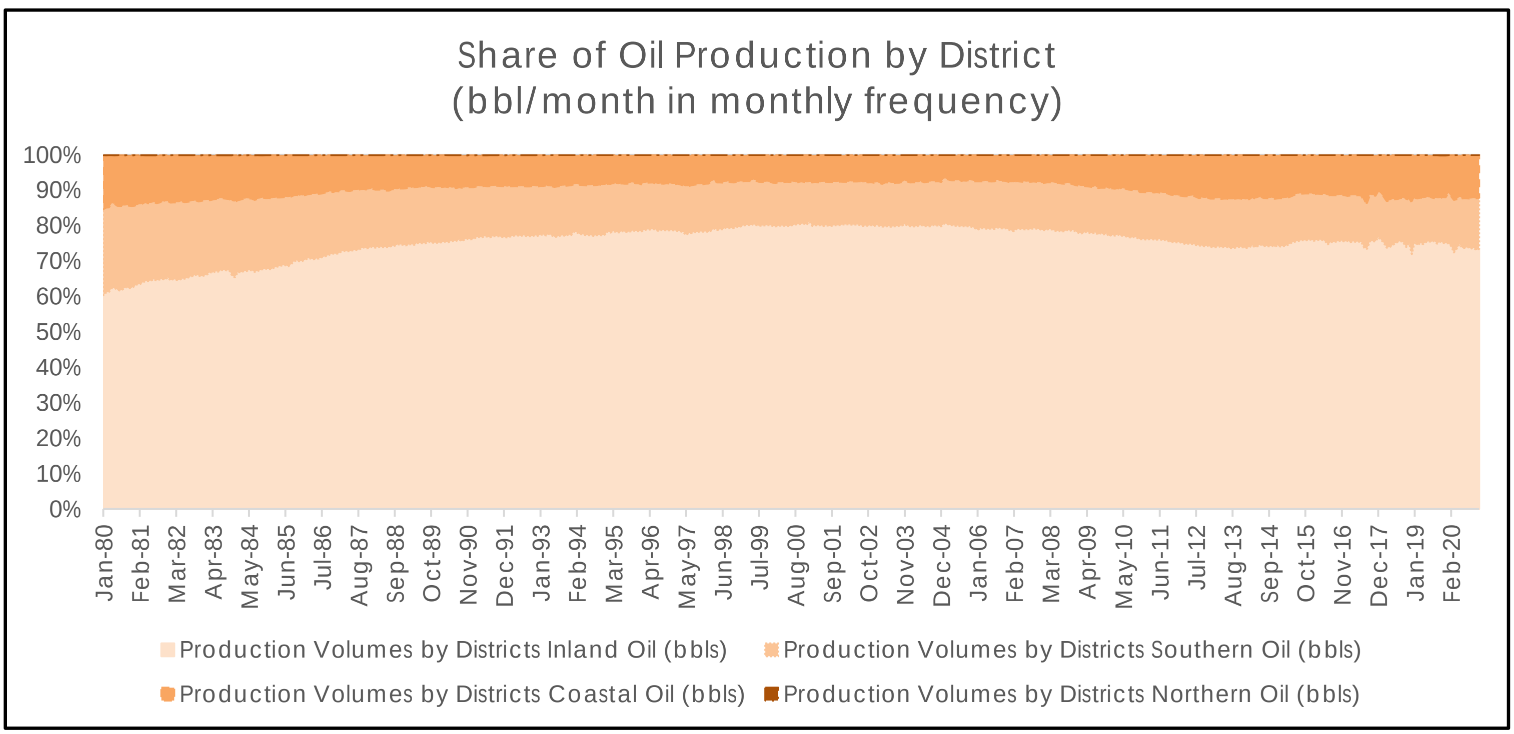


Figure 9: Share of oil production by district in barrels per month in monthly frequency. Notice Inland District oil production increased from about 60 percent in 1980 to about 80 percent by 2000. The share of oil production from Southern district decreased the most between 1980 and 2020.

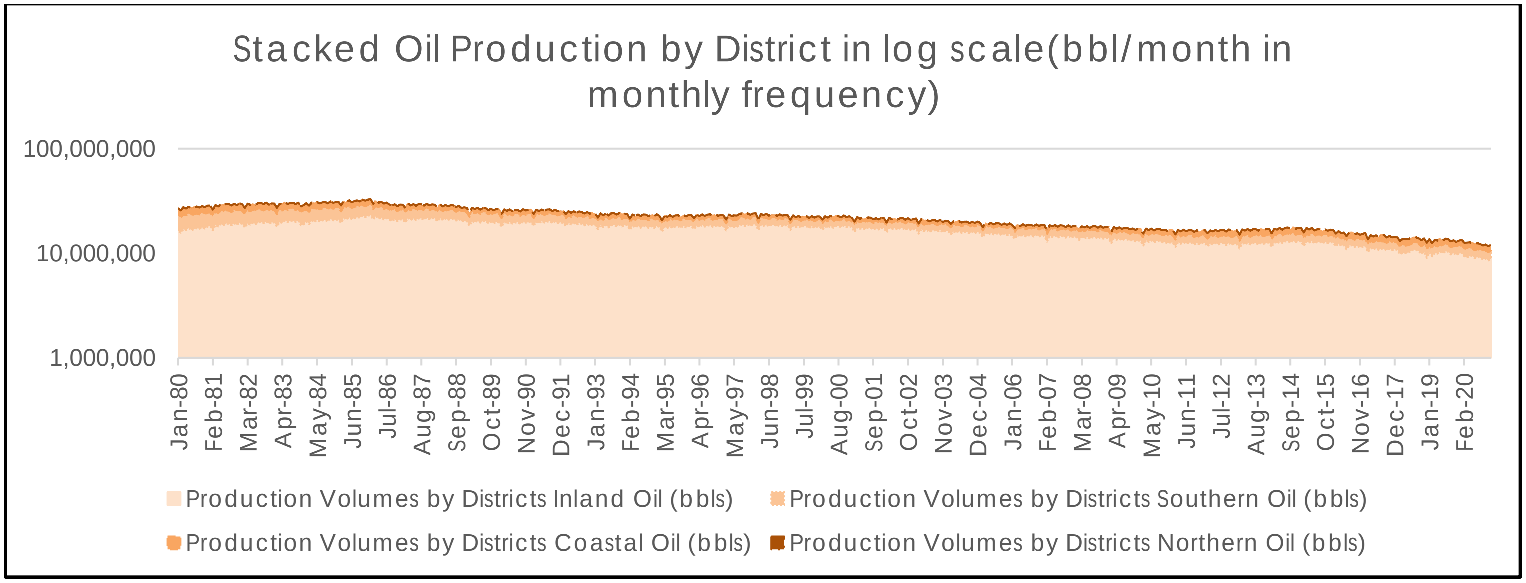


Figure 10: Stacked oil production by district in barrels per month in monthly frequency in logarithmic scale.

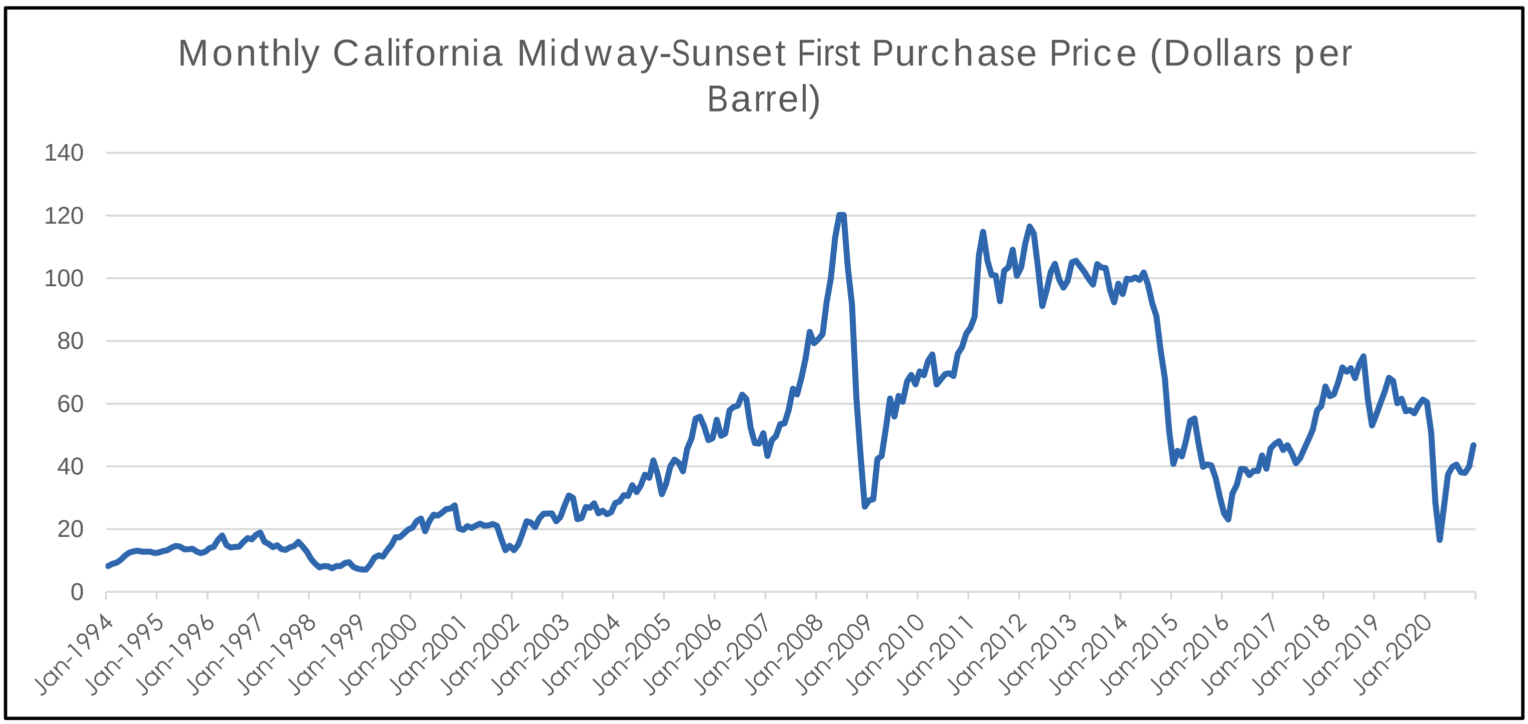


Figure 11: Monthly Midway-Sunset Oil Price. Source: EIA
https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F005006143&f=M

Oil Production from the Ten Largest Fields (MMbbl per year)

Without Federal OCS Production

Field Name	2020	2019	2018	2017	2016
Belridge, South	18.4	20.0	20.8	21.2	22.5
Midway-Sunset	20.0	21.2	21.0	22.2	24.7
Kern River	16.3	17.7	16.3	21.9	24.2
Cymric	11.6	13.1	15.3	16.4	16.9
Wilmington	10.2	10.3	10.8	11.6	12.6
Lost Hills	8.7	9.3	9.7	9.5	10.2
San Ardo	7.3	8.3	8.4	7.2	7.9
Elk Hills	6.3	7.7	8.5	9.1	10.0
Coalinga	5.4	5.8	6.3	6.6	6.4
Poso Creek	4.8	5.4	5.1	4.4	4.2

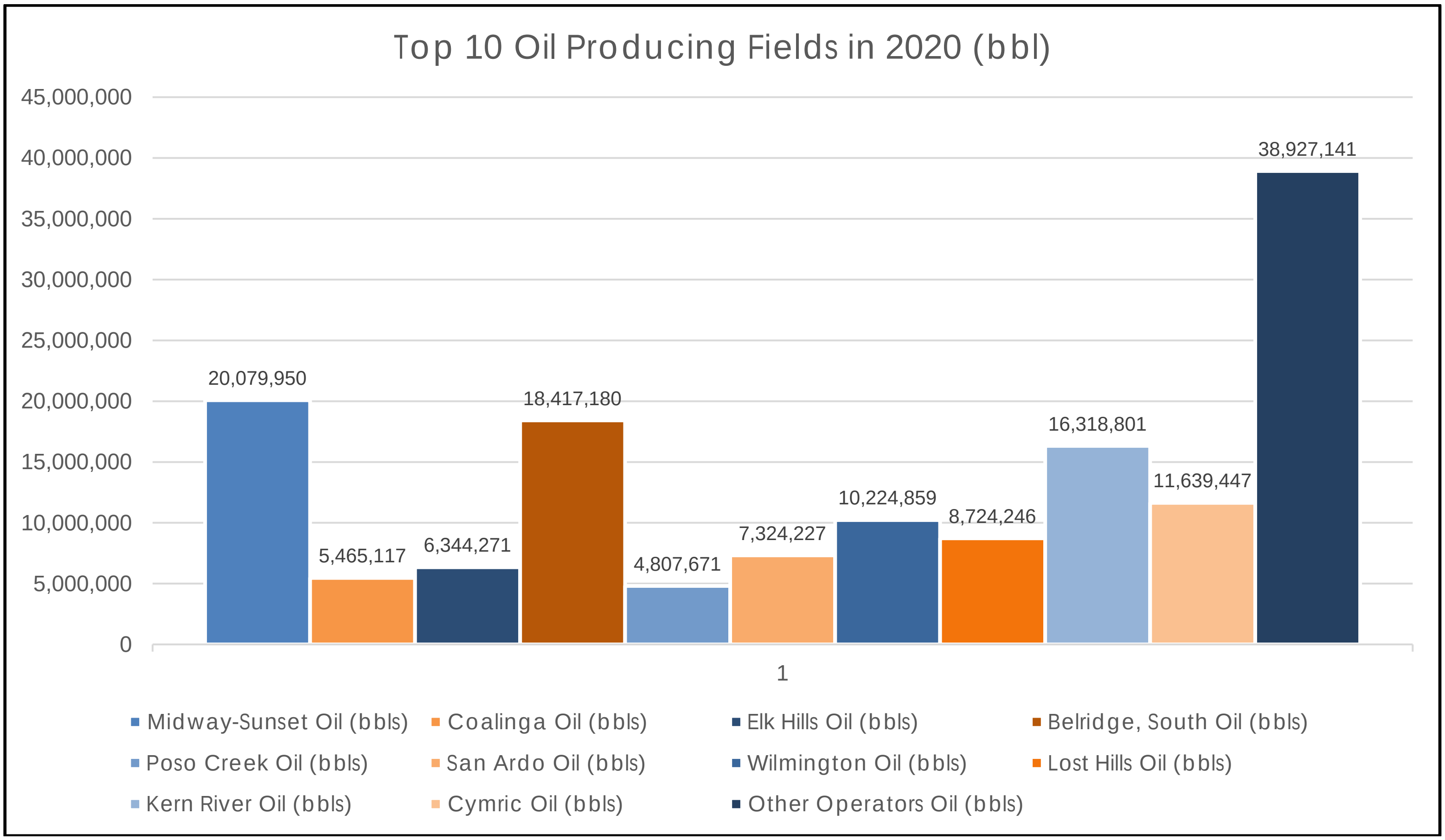


Figure 12. Ten largest producing oil fields in California in 2020.

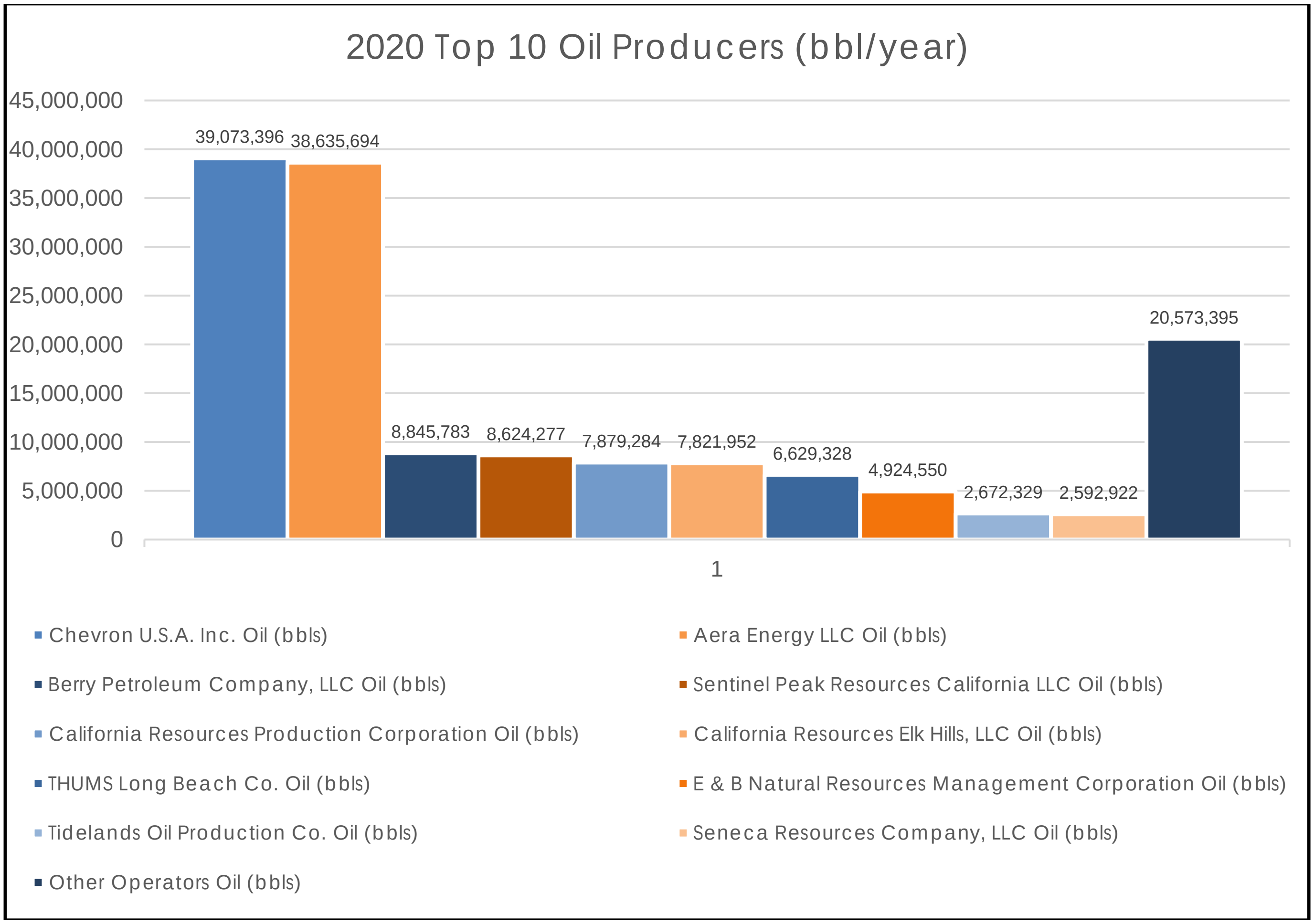


Figure 13: Ten largest oil producers in California in 2020. Eighty-six percent of the oil production came from the top 10 operators in 2020, with Chevron and Aera representing more than half of the total oil production.

GAS PRODUCTION

State Associated & Non-Associated Gross Gas Production (2016-2020) (Bcf)
Without Federal OCS Production

Year	2020	2019	2018	2017	2016
Total Associated	136.6	149	159.8	171.2	174.9
Total Non-Associated	12.6	16.6	18.5	20.3	22.4
Total	149.2	165.6	178.3	191.5	197.3

*Does not equal sum due to rounding.

State Associated & Non-Associated Gross Gas Production (2016-2020) (Bcf)
Without Federal OCS Production

Year	2020	2019	2018	2017	2016
Total Onshore	145.4	162.8	175.4	187.3	192.7
Total Offshore	3.8	2.8	2.9	4.2	4.6
Total	149.2	165.6	178.3	191.5	197.3

*Does not equal sum due to rounding.

2020 Gross Associated Gas Production from the Ten Largest Fields (Bcf/year)

Without Federal OCS Production

Field Name	Gross Gas Production
Elk Hills	71.1
Buena Vista	13.8
Belridge, South	7.3
Midway-Sunset	4.6
Lost Hills	4.6
Wilmington	4.4
Asphalto	3.7
Ventura	2.9
Cymric	1.8
Belridge, North	1.8

Gross Non-Associated Gas Production from the Largest Fields (Bcf/year)

Without Federal OCS Production

Field Name	Gross Gas Production
Rio Vista Gas	2.6
Grimes Gas	2.0
Willows-Beehive Bend Gas	1.8
Sutter Buttes Gas	1.3
Sycamore Gas	0.49
Elk Hills	0.48
Malton-Black Butte Gas	0.33
Tompkins Hill Gas	0.33
Union Island Gas	0.30
Grimes, West, Gas	0.28

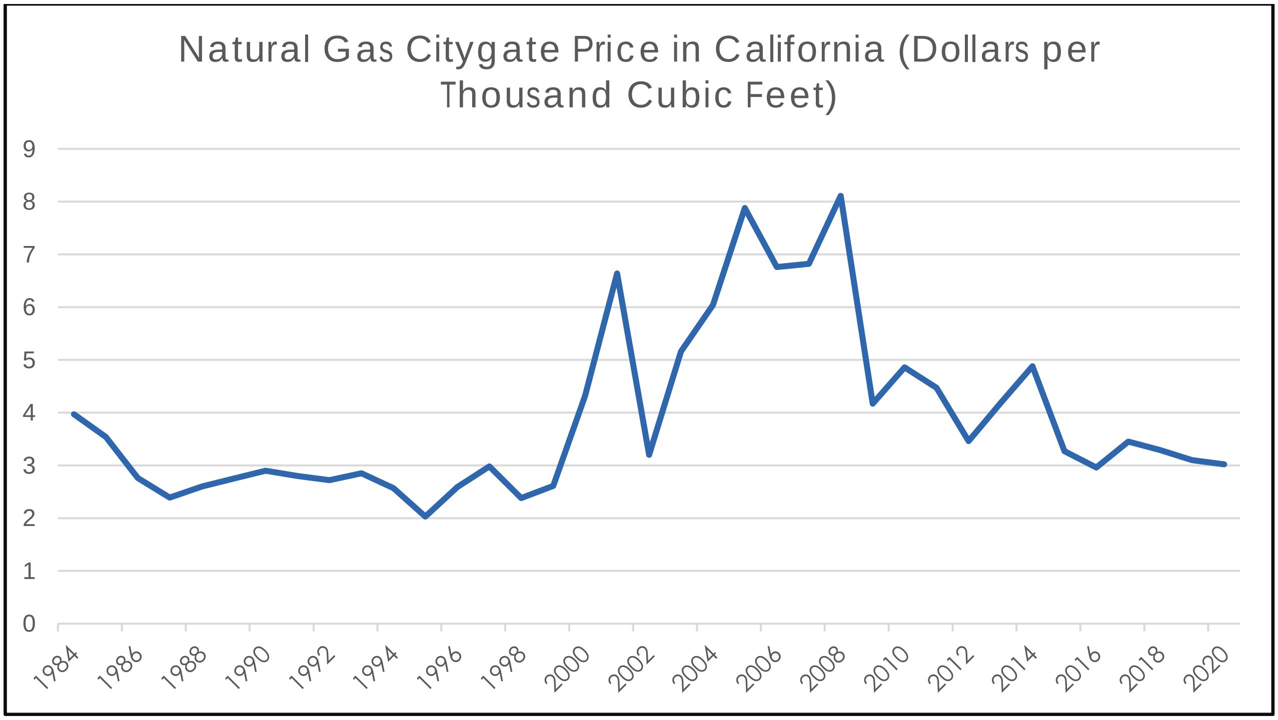


Figure 14: Natural gas Citygate price in California on an annual frequency. Source: U.S. Energy Information Administration (EIA) http://www.eia.gov/dnav/ng/hist/n3050ca3a.htm

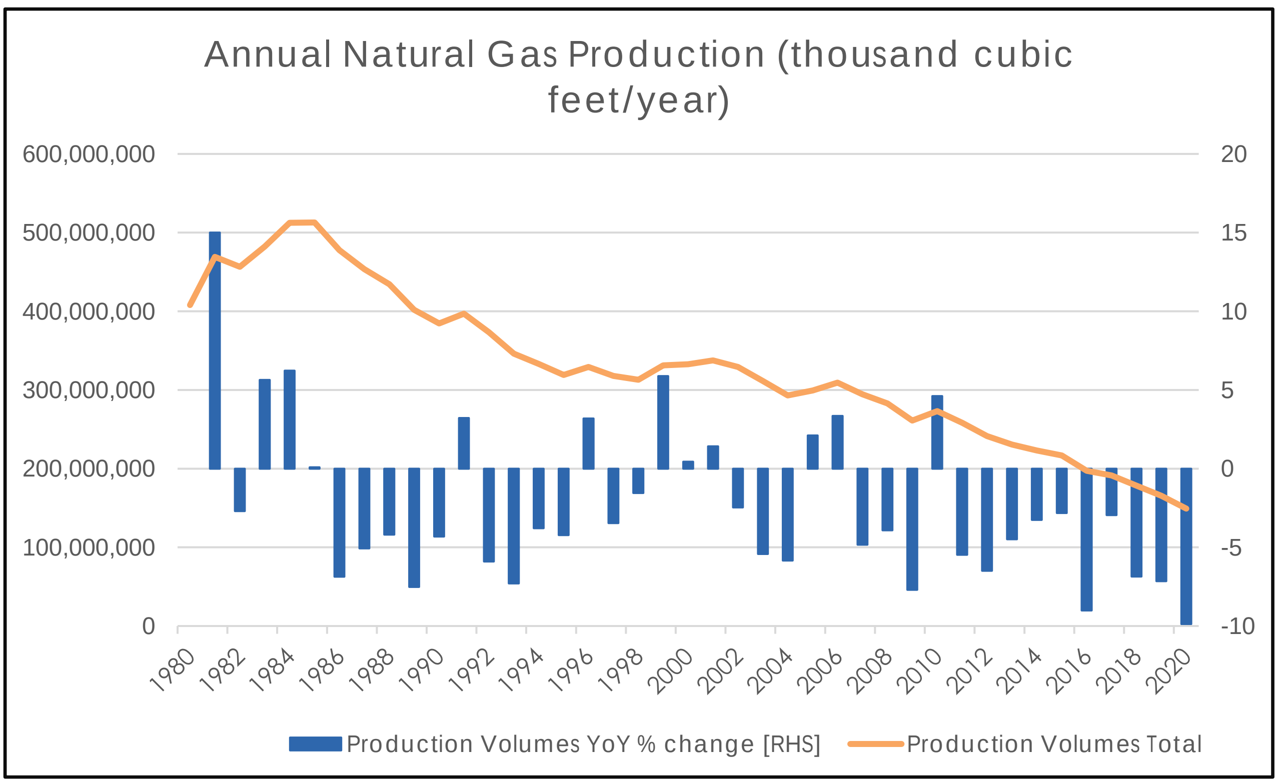


Figure 15: California natural gas production in thousand cubic feet (mcf) per year in annual frequency. Notice yearly natural gas production peaked in 1985 at 512,876,086 mcf/year, equivalent to 1.4 bcf/day. The blue bars represent the year-over-year percentage change in production. Since the peak in 1985, year-over-year natural gas production has increased only during eight years: 1991, 1996, 1999, 2000, 2001, 2005, 2006 and 2010. The average decline rate since the peak in 1985 is 3 percent with an acceleration in the decline since 2011, with the steepest decline in history in 2020 with a 10 percent decline. The cumulative natural gas production drop since 2015 is 31 percent, 5 percent higher than the oil production drop.

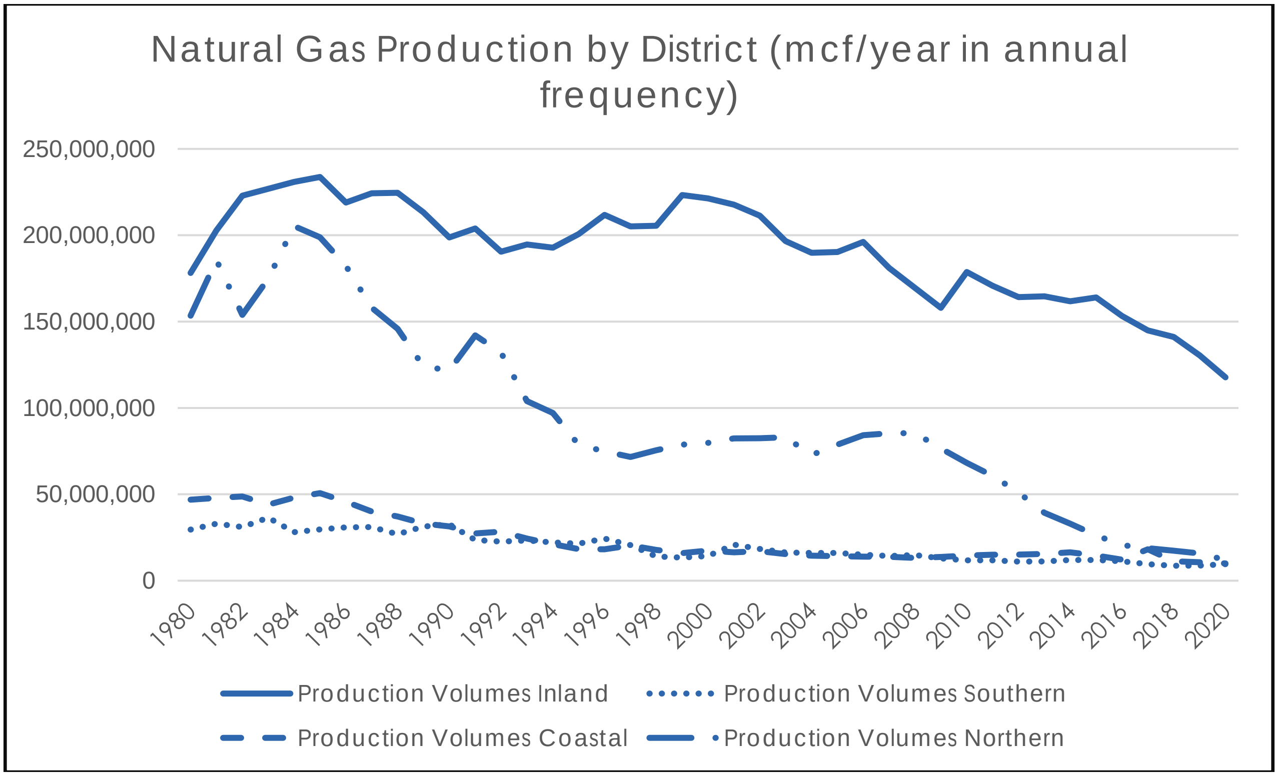


Figure 16: Natural gas production by district in thousand cubic feet per year in annual frequency. Notice Inland district annual natural gas production peaked in 1985 at 233,735,338 mcf/year. Natural gas production in Northern district dropped drastically since 2008.

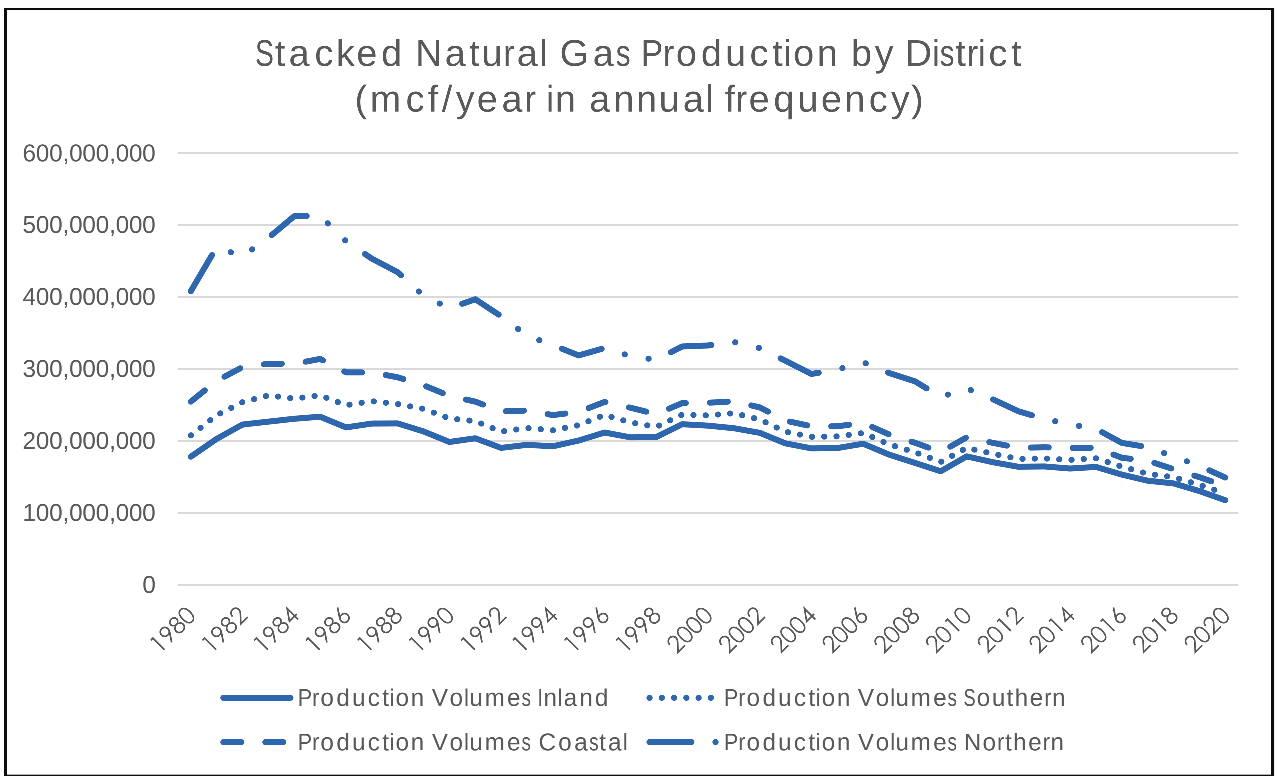


Figure 17: Stacked natural gas production by district in thousand cubic feet per year in annual frequency. Notice the peak in monthly production in January 1985 at 512,876,086 mcf/year.

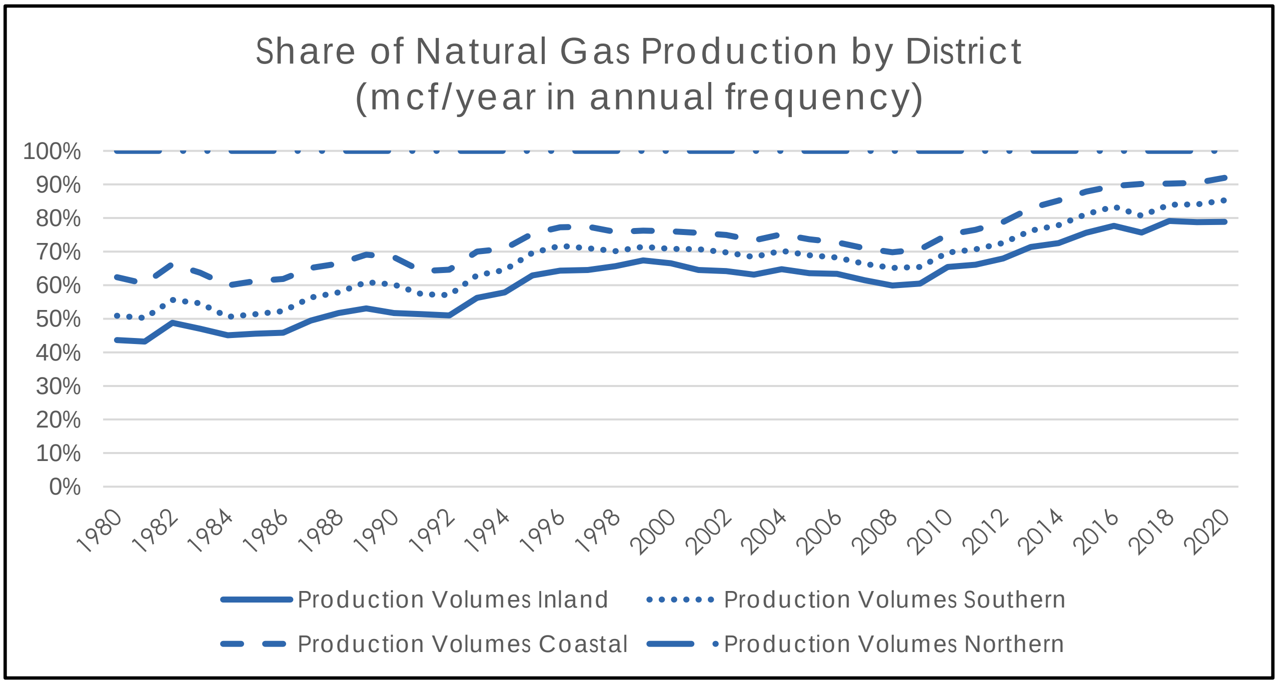


Figure 18: Share of natural gas production by district in thousand cubic feet per year in annual frequency. Notice Inland district monthly production increased from around 45 percent in 1980 to about 80 percent by 2018, taking the majority of the share from Northern district. The share of natural gas production from Northern district decreased the most between 1980 and 2020.

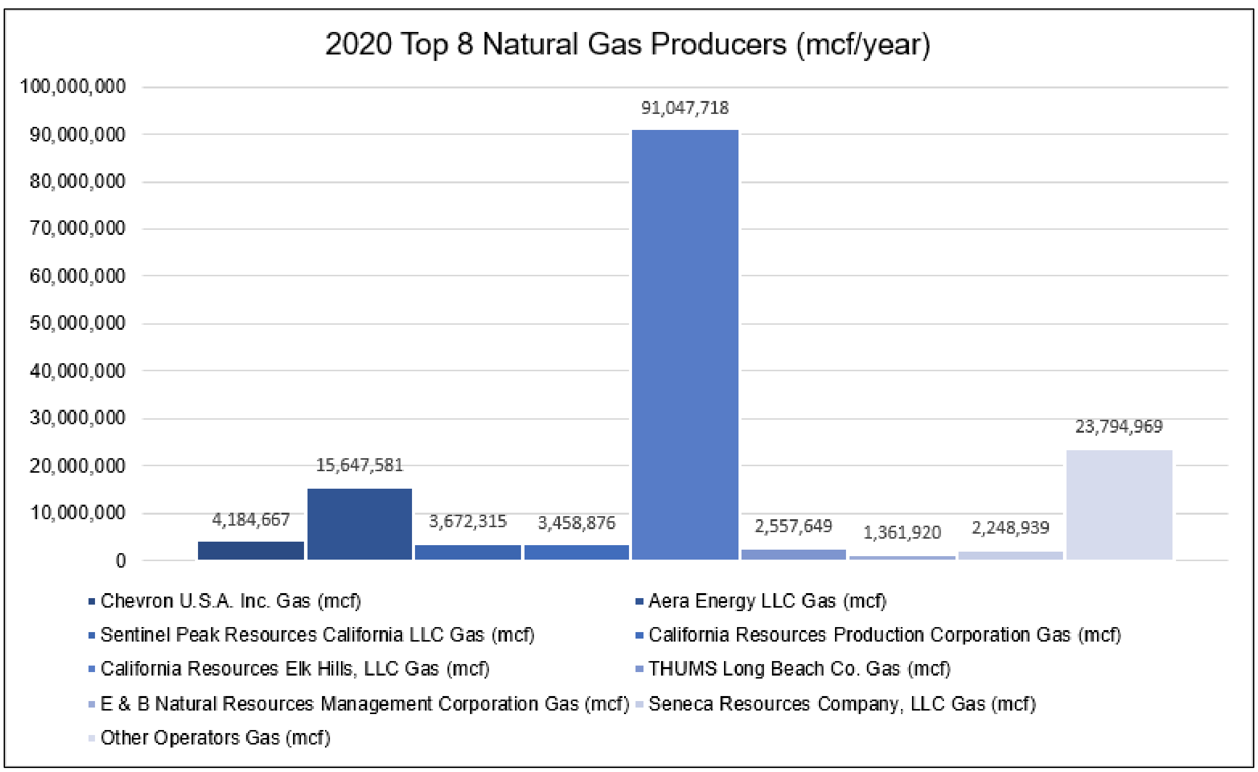


Figure 19: Ten largest natural gas producers in California in 2020. 84 percent of the natural gas production came from the top 10 operators in 2020, with California Resources Elk Hills representing 61 percent of the total natural gasproduction in California in 2020.

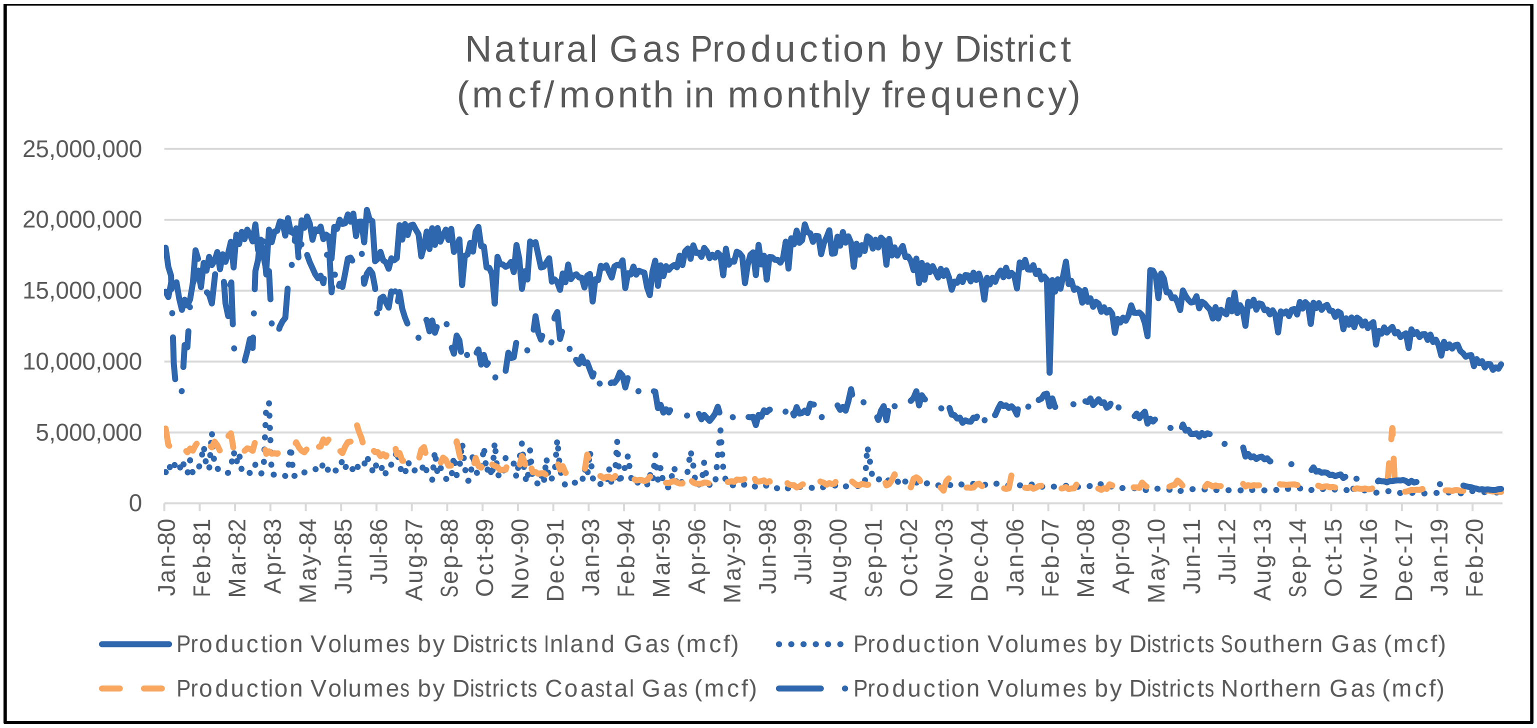


Figure 20: Natural production by district in thousand cubic feet per month in monthly frequency. Notice Inland district monthly production peaked in March 1986 at 20,698,833 mcf/month. Natural Gas production in Southern and Coastal districts are minimal and represented an average of respectively 793,857 mcf/month and833,384 mcf/month in 2020.

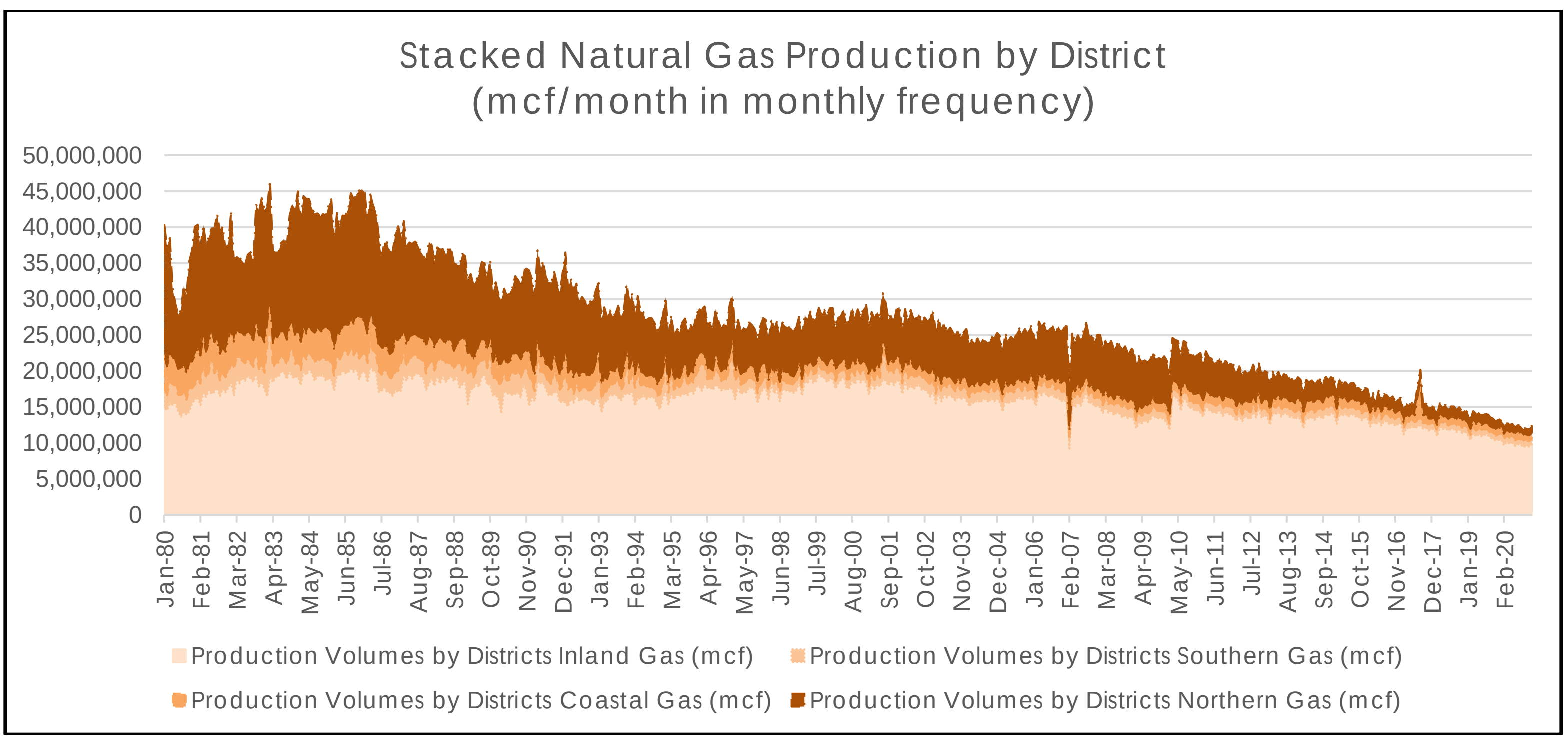


Figure 21: Stacked natural gas production by district in thousand cubic feet per month in monthly frequency. Notice the peak in monthly production in March 1983 at 46,469,126 mcf/month.

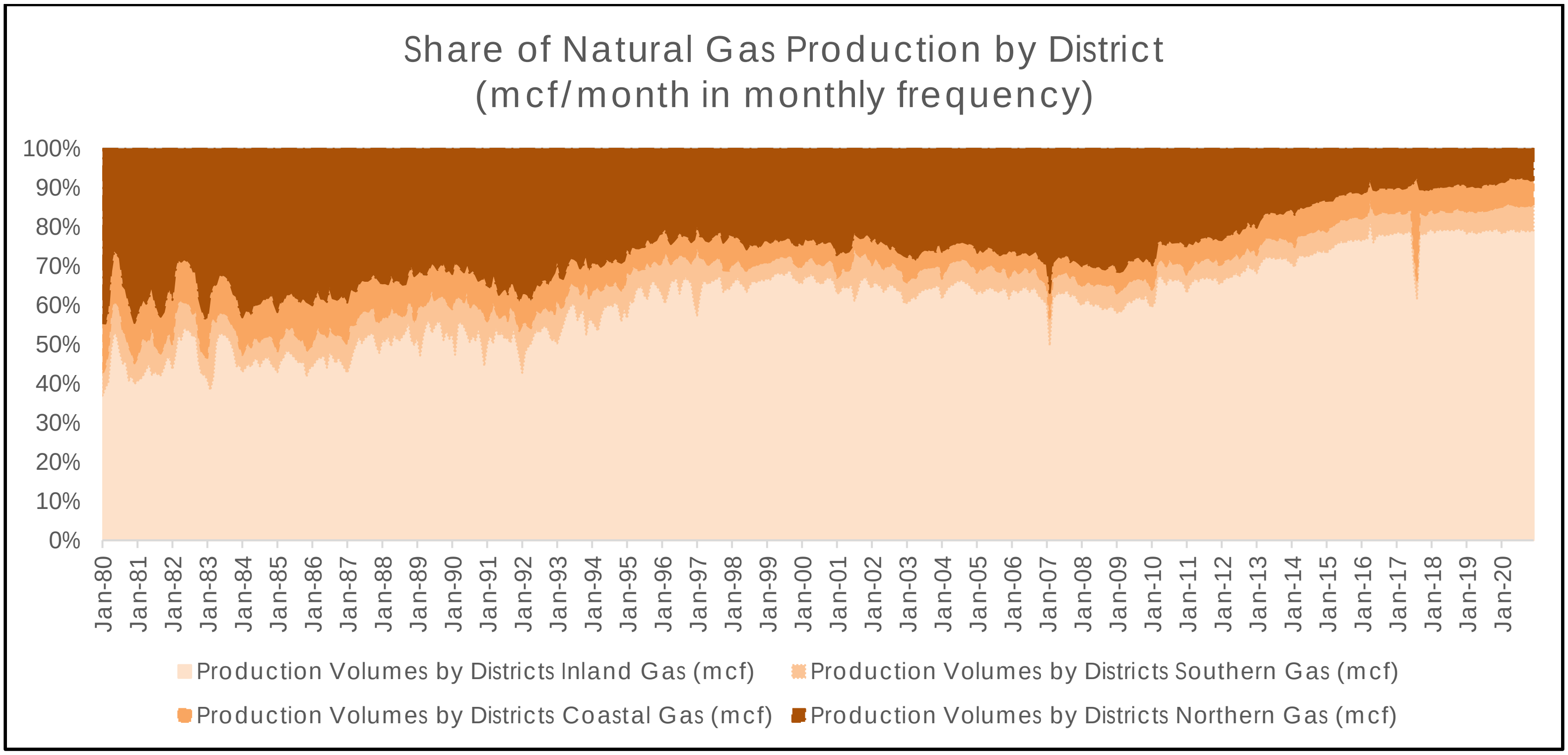


Figure 22: Share of natural gas production by district in thousand cubic feet per month in monthly frequency. Notice Inland district monthly oil production increased from about 35 percent in 1980 to about 70 percent in 2020. The shares of natural gas production from Northern district decreased in two stages in 1993-1996 and in 2010-2015.

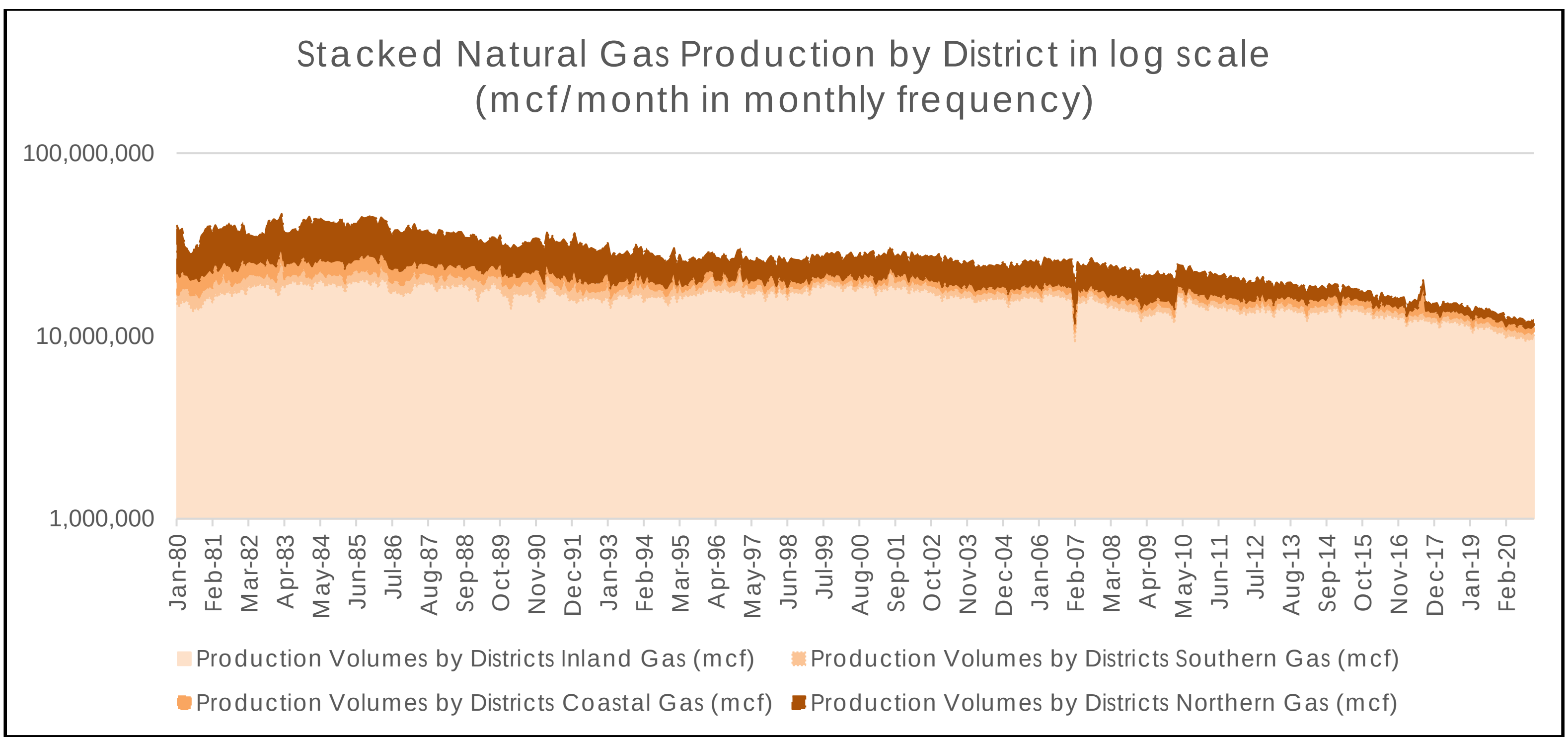


Figure 23: Stacked natural gas production by district in thousand cubic feet per month in monthly frequency in logarithmic scale.

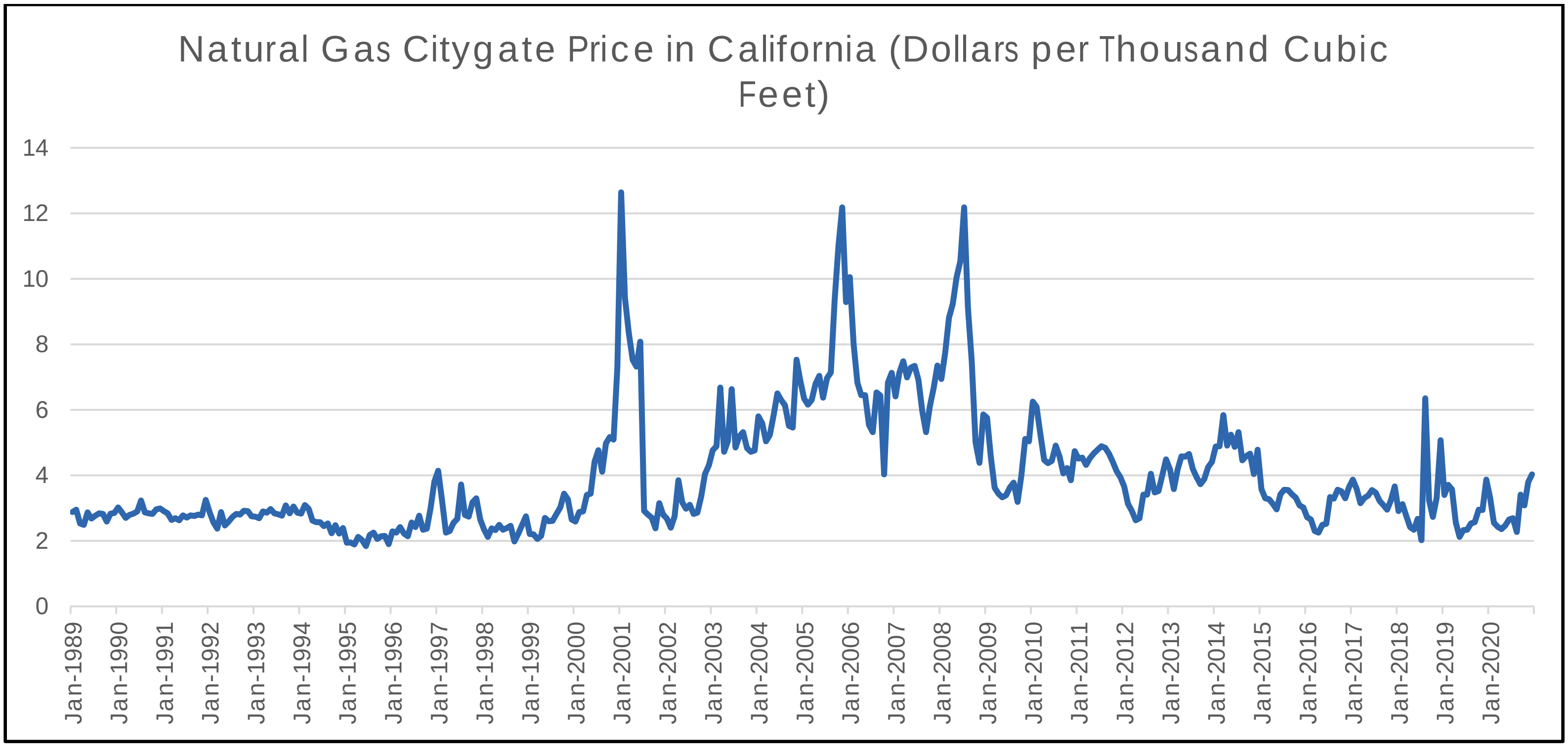


Figure 24: Natural gas Citygate price in California. Source: U.S. Energy Information Administration (EIA)http://www.eia.gov/dnav/ng/hist/n3050ca3m.htm

UNDERGROUND GAS STORAGE

2020 State Gas Storage by District

	Gas Injected (Bcf)	Gas Withdrawn (Bcf)	Net (Bcf)
Coastal	51.2	44.8	6.4
Northern	122.1	91.3	30.8
Southern	3.7	3.3	0.4
Grand Total	**177**	**139.4**	**37.6**

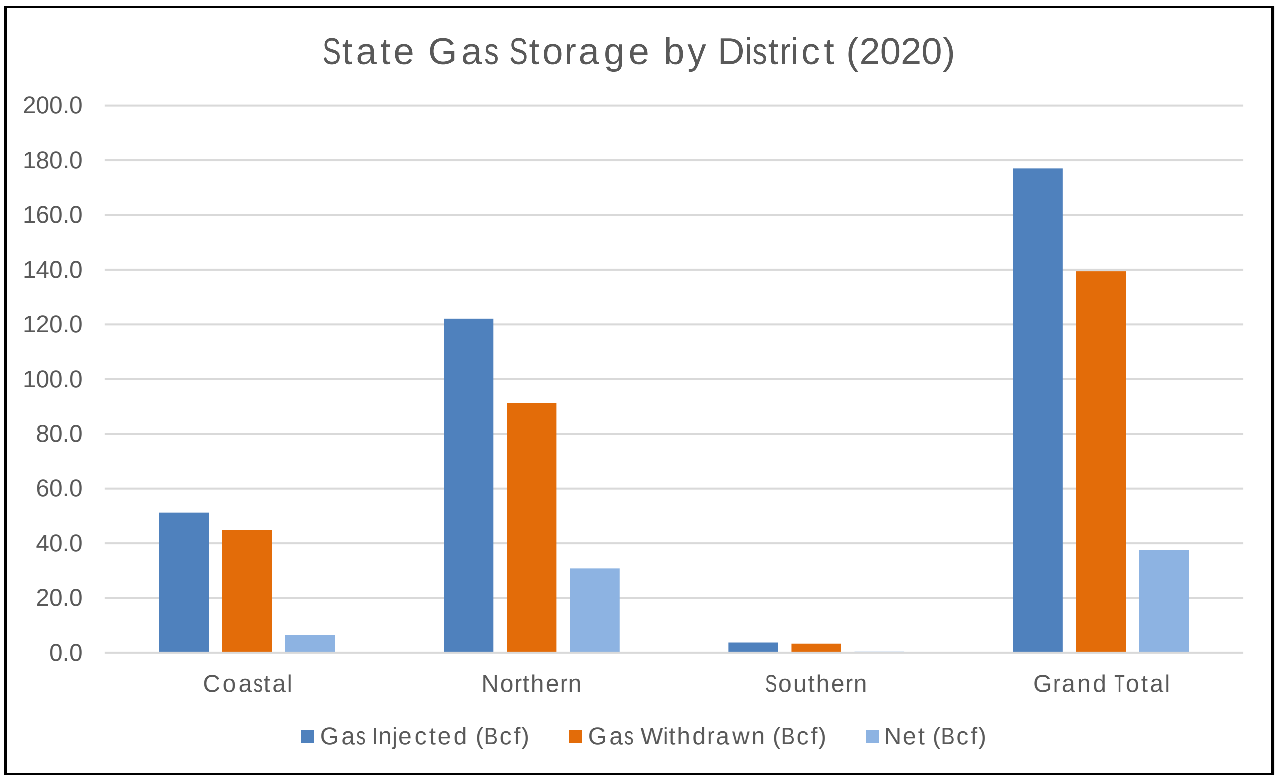


Figure 26: Underground gas storage volume by district in 2020.

2020 CALIFORNIA INJECTION

The table below lists the injection volumes for 2016-2020. Water flood and cyclic steam operations increased from 2019 to 2020, while water disposal, steam flood, and gas injection decreased from 2019 to 2020. There has been no recorded air injection over the past five years.

Injection Volumes (MMbbl or Bcf*)
Without Federal OCS Production

	2020	2019	2018	2017	2016
Water Flood	1,582.9	1,511.9	1,575.9	1,619.6	1,636.2
Water Disposal	733.2	741.2	718.8	694.3	734.7
Steam Flood	345.9	376.1	398.7	395.9	414.1
Cyclic-Steam	243.8	231.3	286.6	133.2	149.4
Gas Injection*	177.1	211.0	129.8	152.9	112.4
Air Injection*	0.0	0.0	0.0	0.0	0.0

* Gas and air volumes in Bcf.

2020 CALIFORNIA NEW WELL OPERATIONS

	2020	2019	2018	2017	2016	2015
Wells Drilled+	693**	852	1,976	996	759	1,016
Wells Completed+	783***	1,071	1,564	1,108	1,111	1,346
Footage Drilled (ft)+	1,630,526***	2,278,447	4,821,253	2,085,937	1,587,498	2,022,697
Drilling Notices Filed+	2,374	3,184	2,530	1,258*	3,917	4,976
Rework Notices Filed	1,691	2,112	2,416	2,547	1,715	3,082
Abandonment Notices Filed++	3,935	3,324	2,786	2,153	1,798	2,120

*2017 Drilling Notices Filed has been amended.
** Based on spud dates in pending and approved well summaries. Previous dates reflected information from approved summaries only.
*** Completion dates extracted from pending and approved summaries. Previous dates reflected information from approved summaries only.
+ Includes new drill, sidetrack and deepen.
++ Includes abandonment and re-abandonment.

[1] Spudding is the process of beginning to drill a well in the oil and gas industry. A larger drill bit is initially used to clear a surface hole,
which is then lined with casing and cement to protect groundwater.

2020 CALIFORNIA OIL, ASSOCIATED GAS, AND WATER PRODUCTION BY DISTRICT AND FIELD

	Oil & Condensate Produced (bbl)	Gross Gas Produced (Mcf)	Water Produced (bbl)
Coastal			
Offshore			
Elwood	0	0	0
Elwood, South, Offshore	0	0	0
Rincon	1,067	584	312
Onshore			
Aliso Canyon	85,322	125,305	448,393
Any Field	17,203	40,676	1,036,594
Arroyo Grande	533,196	494,311	8,694,860
Bardsdale	101,348	146,212	32,029
Barham Ranch	69,047	145,360	107,351
Big Mountain	1,382	12,304	4,322
Bitterwater	2,169	0	0
Cabrillo	14,333	36,744	33,821
Canada Larga	0	0	0
Careaga Canyon	2,091	12,809	136,502
Cascade	70,855	119,613	122,927
Casmalia	83,052	16,305	3,390,166
Castaic Hills	4,179	1,216	4,546
Cat Canyon	1,207,972	892,563	8,902,176
Chaffee Canyon	564	8,372	640
Cuyama, South	142,483	90,256	12,436,866
Del Valle	26,206	12,705	97,788
Eureka Canyon	0	0	0
Fillmore	185	35	970
Four Deer (ABD)	5,870	15,234	108,833
Goleta	0	0	0
Hasley Canyon	16,213	13,842	34,609
Hollister	0	0	0
Holser	13,561	8,884	11,794
Honor Rancho	18,719	5,718	104,946
Hopper Canyon	0	0	0
Jesus Maria	0	0	0
La Goleta Gas	224	0	2,636
Lompoc	200,552	138,412	17,076,404
Los Alamos	8,716	5,050	0
Lynch Canyon	50,513	0	2,072,298
McCool Ranch	0	0	0

Monroe Swell	10,812	0	23,228
Montalvo, West	133,583	70,656	6,817,267
Moody Gulch (ABD)	0	0	0
Moorpark West	4,812	1,977	4,417
Morales Canyon	0	0	0
Newhall	0	0	0
Newhall-Potrero	1,606	439	763
Oak Canyon	12,819	2,973	138,131
Oak Park	389	401	1,294
Oakridge	76,259	41,057	600,477
Oat Mountain	74,796	64,544	63,459
Ojai	260,991	722,637	365,875
Orcutt	741,278	694,513	30,342,885
Oxnard	94,214	4,250	82,043
Paris Valley	0	0	0
Piru Creek (ABD)	0	0	0
Placerita	442,610	0	22,295,274
Ramona	26,494	42,700	20,511
Ramona, North	0	0	0
Rincon	175,703	180,868	1,609,292
Russell Ranch	42,139	62,478	1,166,552
San Ardo	7,324,227	1,028,070	148,683,004
San Miguelito	235,053	185,201	2,393,046
Santa Clara Avenue	5,506	2,253	6,477
Santa Maria Valley	37,084	64,007	280,776
Santa Paula (ABD)	0	0	0
Santa Susana	1,041	1,955	3,632
Sargent	14,483	13,798	14,371
Saticoy	16,005	25,696	48,304
Sespe	319,499	764,340	286,193
Shiells Canyon	34,101	118,832	430,119
Simi	0	0	0
South Mountain	267,211	455,987	252,786
Tapia	8,524	430	193,911
Tapo Canyon, South	2,173	433	349
Tapo Ridge	0	0	0
Tapo, North	0	0	0
Temescal	38,898	12,237	98,275
Timber Canyon	33,207	104,992	11,581
Torrey Canyon	50,903	93,360	46,975
Vallecitos	8,498	14,607	1,083
Ventura	4,613,499	2,867,374	52,114,463
Wayside Canyon	9,658	7,864	50,089
West Mountain	3,280	4,643	3,988
Zaca	85,606	2,530	3,303,042

Inland			
Onshore			
Ant Hill	11,914	0	998,381
Antelope Hills	78,501	8,400	667,474
Antelope Hills, North	141,553	9,651	2,505,131
Any Field	441,313	891,111	1,118,144
Asphalto	173,688	3,725,108	8,719,494
Beer Nose	9,769	3,761	282
Belgian Anticline	31,306	76,112	93,963
Bellevue	21,519	4,873	224,543
Bellevue, West	25,859	21,798	52,842
Belridge, North	1,532,150	1,756,260	28,593,951
Belridge, South	18,417,180	7,336,669	302,180,367
Blackwells Corner	8,922	0	44,225
Bowerbank	0	0	0
Buena Vista	903,128	13,824,809	34,300,836
Burrel	18,339	18,113	741,965
Burrel, Southeast	0	0	0
Cal Canal Gas	18,669	60,895	119,211
Calders Corner	0	0	0
Camden	0	0	0
Canal	4,927	2,047	31,409
Canfield Ranch	76,147	61,033	512,825
Carneros Creek	3,687	0	12,557
Chico-Martinez	46,475	0	701,563
Cienaga Canyon	9,192	37,645	180,178
Coalinga	5,465,117	486,716	63,340,646
Coalinga, East, Extension	0	0	0
Coles Levee, North	93,370	91,496	259,620
Coles Levee, South	46,579	289,102	40,206
Comanche Point	11,026	0	532,857
Cymric	11,674,490	1,839,168	119,201,691
Deer Creek	25,287	0	2,213,169
Deer Creek, North	671	0	5,102
Devils Den	8,369	0	30,851
Dyer Creek	5,560	0	481,032
Edison	555,913	132,951	8,899,247
Edison, Northeast	0	0	0
Elk Hills	6,344,271	71,541,816	95,992,415
Fruitvale	429,455	153,476	6,462,647
Greeley	110,760	166,262	2,445,933
Guijarral Hills	5,080	3,808	53,180
Helm	23,219	2,002	136,491
Jacalitos	81,194	41,924	270,223
Jasmin	114,113	0	20,730,055
Jerry Slough (ABD)	0	0	0

Kern Bluff	9,633	0	830,167
Kern Front	2,900,660	63,957	147,031,674
Kern River	16,318,801	776,765	244,566,982
Kettleman City (ABD)	0	0	0
Kettleman MiddleDome	11,796	14,800	13,600
Kettleman North Dome	109,334	222,200	1,874,895
Kreyenhagen (ABD)	0	0	0
Landslide	10,665	6,611	223,731
Los Lobos	305	0	0
Lost Hills	8,724,584	4,566,721	118,506,113
Lost Hills, Northwest	11,767	10,683	301,156
McDonald Anticline	31,856	502	206,879
McKittrick	3,701,977	643,536	41,161,244
Midway-Sunset	20,079,950	4,636,087	178,055,228
Monument Junction	33,107	52,059	261,462
Mount Poso	1,141,152	35,838	52,693,513
Mountain View	58,376	30,339	318,559
Paloma	14,298	100,128	15,476
Pioneer	2,761	3,620	640
Pleasant Valley	0	0	0
Pleito	380,072	226,422	640,544
Poso Creek	4,807,671	515,239	184,254,958
Pyramid Hills	47,336	7,920	229,745
Railroad Gap	73,300	1,741,165	1,456,367
Raisin City	65,317	15,080	2,649,955
Rio Bravo	174,444	322,816	5,825,846
Rio Viejo	89,282	34,654	152,776
Riverdale	19,229	0	86,910
Rose	166,585	74,595	702,908
Rosedale	11,304	0	3,453
Rosedale Ranch	85,629	63,861	3,806,782
Round Mountain	2,462,349	248,195	163,807,368
San Emidio Nose	14,158	8,466	72,547
San Joaquin	0	0	0
Semitropic	22,572	10,199	28,045
Shafter, North	357,170	267,333	1,360,601
Stockdale	90,958	32,633	35,170
Strand	1,937	1,610	1,506
Tejon	78,920	41,992	6,026,488
Tejon Hills	5,400	960	162,869
Tejon, North	17,425	154,914	16,870
Temblor East (ABD)	0	0	0
Temblor Ranch	0	0	0
Ten Section	50,523	24,601	1,442,816

Trico Gas	0	0	0
Tulare Lake	0	0	0
Union Avenue	17,479	8,225	48,592
Valpredo	0	0	0
Van Ness Slough	0	0	0
Wasco	0	0	0
Welcome Valley	0	0	0
Wheeler Ridge	44,948	37,861	145,188
White Wolf	9,055	4,076	2,257
Yowlumne	174,558	135,425	2,819,600
Northern			
Onshore			
Afton Gas	0	0	0
Any Field	0	61,803	1,716
Any Field - Coastal District	0	2,375	43
Any Field - Inland Dis- trict	0	2,375	43
Any Field - Northern District	0	2,375	43
Any Field - Southern District	0	2,375	43
Arbuckle Gas	0	3,774	5
Bounde Creek Gas	0	82,119	1,253
Brentwood	66,925	33,302	38,703
Brentwood, East, Gas	0	0	0
Buckeye Gas	0	167,458	234
Bunker Gas	0	0	0
Butte Sink Gas	0	0	0
Butte Slough Gas	0	135,452	223
Cache Creek Gas	0	0	0
Chowchilla Gas	0	0	0
Clarksburg Gas	0	0	0
Collegeville, East, Gas	0	0	0
Compton Landing Gas	0	17,564	32
Conway Ranch Gas	0	0	0
Denverton Creek Gas	3	20,285	1,301
Dunnigan Hills Gas	0	0	0
Durham Gas	0	0	0
Dutch Slough Gas	0	0	0
East Islands Gas	0	0	0
Everglade Gas	0	0	0
French Camp Gas	0	162,725	2,338
Gill Ranch Gas	0	33,288	10,351
Grimes Gas	0	1,966,296	38,066
Grimes, West, Gas	0	283,556	1,843
Grizzly Bluff Gas	0	25,245	12

Half Moon Bay	46	0	0
Hood-Franklin Gas	0	0	0
Howells Point Gas	0	0	0
King Island Gas	0	31,013	0
Kirby Hill Gas	0	0	5,786
Kirk Gas	0	99,712	2,018
Kirkwood Gas	0	0	0
Knights Landing Gas	0	0	0
La Honda	0	0	0
Larkin, West, Gas	0	0	0
Lathrop Gas	0	186,448	10,709
Lindsey Slough Gas	70	149,851	2,359
Little Butte Creek Gas	0	0	0
Livermore	3,388	452	23,981
Lodi Gas	0	0	8,510
Lone Star Gas	0	71,789	833
Lone Tree Creek Gas	0	0	0
Los Medanos Gas	0	18,820	60
Maine Prairie Gas	0	0	0
Malton-Black Butte Gas	0	329,000	20,747
McDonald Island Gas	0	0	4,098
McMullin Ranch Gas	0	0	0
Medora Lake Gas	0	0	0
Merrill Avenue Gas	0	0	0
Merrill Avenue, Southeast, Gas	0	6,843	0
Millar Gas	0	0	0
Moffat Ranch Gas	0	80,824	372
Moon Bend Gas	0	132,022	3,788
Nicolaus Gas	0	0	0
Oakdale Gas	0	0	0
Oil Creek	0	0	0
Orland Gas	0	0	0
Pierce Road Gas	0	0	0
Pleasant Creek Gas	0	0	0
Princeton Gas	0	0	44
Putah Sink Gas	0	0	0
Rancho Capay Gas	0	78,066	6
Rice Creek Gas	0	192,578	2,720
Rice Creek, East, Gas	0	135,216	228
Rindge Tract Gas	0	0	0
Rio Vista Gas	3,523	2,558,154	74,010
River Island Gas	0	34,155	165
Robbins Gas	0	0	0
Roberts Island Gas	0	0	0
Ryer Island Gas	0	55,620	0
Sacramento Airport Gas	0	0	0

Stegeman Gas	0	0	0
Sugarfield Gas	0	0	0
Suisun Bay Gas	0	52,530	2,959
Sutter Buttes Gas	0	1,328,104	26,016
Sutter City Gas	0	145,408	2,341
Sycamore Gas	0	485,770	12,104
Sycamore Slough Gas	0	2,398	0
Thornton, W.-Walnut Grove Gas	0	0	0
Tisdale Gas	0	144,177	3,256
Todhunters Lake Gas	0	12,932	0
Tompkins Hill Gas	0	325,190	5,342
Union Island Gas	0	295,896	8,341
Van Sickle Island Gas	124	83,287	953
Vernalis Gas	0	17,168	46
West Butte Gas	0	62,073	1,252
Wild Goose Gas	0	0	116
Williams Gas	0	42,619	194
Willow Slough Gas	0	0	0
Willows-Beehive Bend Gas	0	1,813,962	43,851
Winchester Lake Gas	0	0	0
Winters Gas	0	0	0
Southern			
Offshore			
Belmont Offshore	576,825	242,865	14,717,409
Huntington Beach	769,923	356,760	32,942,149
Wilmington	7,610,177	3,205,722	442,141,806
Onshore			
Any Field	0	0	0
Bandini	8,627	0	32,865
Beverly Hills	321,015	443,695	4,183,553
Brea-Olinda	972,227	520,512	7,183,555
Cheviot Hills	35,456	33,555	116,302
Chino-Soquel	570	0	0
Coyote, East	80,373	11,886	865,856
Dominguez	5,404	7,319	13,498
El Segundo	16,602	4,918	242,215
Esperanza	2,019	627	1,626
Howard Townsite	9,042	20,250	1,757
Huntington Beach	816,477	235,585	29,479,606
Hyperion	3,423	0	415
Inglewood	1,530,112	791,995	104,634,100
Las Cienegas	101,270	88,922	1,701,750
Long Beach	1,145,938	842,854	23,434,250
Long Beach Airport	7,282	1,089	76,649
Los Angeles City	8,309	9,520	21,919
Los Angeles Downtown	21,714	23,548	448,415

Los Angeles, East	60	77	0
Mahala	6,587	34,740	797
Montebello	229,654	103,828	16,700,969
Newport	0	26,636	0
Newport, West	52,258	27,609	1,244,922
Old Wilmington (ABD)	5,431	303	4,503
Olive	45,177	7,235	129,969
Playa Del Rey	48,698	0	1,092,833
Potrero (ABD)	0	0	0
Prado-Corona	0	0	0
Richfield	155,929	23,758	2,504,815
Rosecrans	99,940	41,630	2,545,136
Rosecrans, South	9,394	12,854	67,916
Salt Lake	37,149	55,505	198,393
Salt Lake, South	8,034	14,864	368,041
San Vicente	164,308	209,424	454,755
Sansinena	216,082	362,927	174,561
Santa Fe Springs	347,177	38,228	16,447,701
Sawtelle	65,456	33,946	85,079
Seal Beach	355,064	254,674	6,267,678
Torrance	256,963	60,261	5,193,633
Walnut	7,210	0	31,950
Whittier	94,579	184,210	178,292
Wilmington	4,669,470	1,191,953	232,717,201
Grand Total	**148,272,818**	**149,230,435**	**3,140,364,199**

2020 SUMMARY OF CALIFORNIA OIL, ASSOCIATED GAS, AND WATER PRODUCTION

	Oil & Condensate Produced (bbl)	Gross Gas Produced (MCF)	Water Produced (bbl)
Coastal			
Offshore	1,067	584	312
Onshore	17,882,915	10,000,030	326,615,405
Inland			
Onshore	109,397,353	117,729,094	1,864,736,189
Northern			
Onshore	74,079	11,974,443	363,454
Southern			
Offshore	8,956,925	3,805,347	489,801,364
Onshore	11,960,479	5,720,938	458,847,475
Grand Total	**148,272,818**	**149,230,435**	**3,140,364,199**

2020 CALIFORNIA CONDENSATE, NON-ASSOCIATED GAS, AND WATER PRODUCTION BY DISTRICT AND FIELD

	Condensate Produced (bbl)	Gross Gas Produced (Mcf)	Water Produced (bbl)
Coastal			
Onshore			
Aliso Canyon	0	0	0
Cuyama, South	90	76	9,465
Del Valle	617	0	14,013
Hollister	0	0	0
La Goleta Gas	0	0	0
Montalvo, West	0	0	0
Tapia	0	0	0
Inland			
Onshore			
Antelope Hills	0	0	0
Belgian Anticline	0	17,631	0
Bowerbank	0	0	0
Buena Vista	0	67,321	0
Cal Canal Gas	18,669	60,895	119,211
Canal	0	0	0
Coles Levee, North	6,669	429	2,529
Elk Hills	0	476,847	0
Kettleman North Dome	0	0	0
Lost Hills	338	262	1,940
Monument Junction	0	0	0
Mountain View	0	0	0
Paloma	0	0	0
Railroad Gap	0	0	0
Rio Bravo	0	33,525	387,173
Semitropic	0	0	0
Strand	0	0	0
Ten Section	0	0	0
Trico Gas	0	0	0
Northern			
Onshore			
Afton Gas	0	0	0
Any Field	0	61,803	1,716

Any Field - Coastal District	0	2,375	43
Any Field - Inland District	0	2,375	43
Any Field - Northern District	0	2,375	43
Any Field - Southern District	0	2,375	43
Arbuckle Gas	0	3,774	5
Bounde Creek Gas	0	82,119	1,253
Brentwood, East, Gas	0	0	0
Buckeye Gas	0	167,458	234
Bunker Gas	0	0	0
Butte Sink Gas	0	0	0
Butte Slough Gas	0	135,452	223
Cache Creek Gas	0	0	0
Chowchilla Gas	0	0	0
Clarksburg Gas	0	0	0
Collegeville, East, Gas	0	0	0
Compton Landing Gas	0	17,564	32
Conway Ranch Gas	0	0	0
Denverton Creek Gas	3	20,285	1,301
Dunnigan Hills Gas	0	0	0
Durham Gas	0	0	0
Dutch Slough Gas	0	0	0
East Islands Gas	0	0	0
Everglade Gas	0	0	0
French Camp Gas	0	162,725	2,338
Gill Ranch Gas	0	33,288	14
Grimes Gas	0	1,966,296	38,066
Grimes, West, Gas	0	283,556	1,843
Grizzly Bluff Gas	0	25,245	12
Hood-Franklin Gas	0	0	0
Howells Point Gas	0	0	0
King Island Gas	0	31,013	0
Kirby Hill Gas	0	0	0
Kirk Gas	0	99,712	2,018
Kirkwood Gas	0	0	0
Knights Landing Gas	0	0	0
Larkin, West, Gas	0	0	0
Lathrop Gas	0	186,448	10,709
Lindsey Slough Gas	70	149,851	2,359
Little Butte Creek Gas	0	0	0
Lone Star Gas	0	71,789	833
Lone Tree Creek Gas	0	0	0
Los Medanos Gas	0	18,820	60
Maine Prairie Gas	0	0	0
Malton-Black Butte Gas	0	329,000	20,747

McMullin Ranch Gas	0	0	0
Medora Lake Gas	0	0	0
Merrill Avenue Gas	0	0	0
Merrill Avenue, Southeast, Gas	0	6,843	0
Millar Gas	0	0	0
Moffat Ranch Gas	0	80,824	372
Moon Bend Gas	0	132,022	3,788
Nicolaus Gas	0	0	0
Oakdale Gas	0	0	0
Orland Gas	0	0	0
Pierce Road Gas	0	0	0
Princeton Gas	0	0	0
Putah Sink Gas	0	0	0
Rancho Capay Gas	0	78,066	6
Rice Creek Gas	0	192,578	2,720
Rice Creek, East, Gas	0	135,216	228
Rindge Tract Gas	0	0	0
Rio Vista Gas	3,523	2,558,154	74,010
River Island Gas	0	34,155	165
Robbins Gas	0	0	0
Roberts Island Gas	0	0	0
Ryer Island Gas	0	55,620	0
Sacramento Airport Gas	0	0	0
Stegeman Gas	0	0	0
Sugarfield Gas	0	0	0
Suisun Bay Gas	0	52,530	2,959
Sutter Buttes Gas	0	1,328,104	26,016
Sutter City Gas	0	145,408	2,341
Sycamore Gas	0	485,770	12,104
Sycamore Slough Gas	0	2,398	0
Thornton, W.-Walnut Grove Gas	0	0	0
Tisdale Gas	0	144,177	3,256
Todhunters Lake Gas	0	12,932	0
Tompkins Hill Gas	0	325,190	5,342
Union Island Gas	0	295,896	8,341
Van Sickle Island Gas	124	83,287	953
Vernalis Gas	0	17,168	46
West Butte Gas	0	62,073	1,252
Williams Gas	0	42,619	194
Willow Slough Gas	0	0	0
Willows-Beehive Bend Gas	0	1,813,962	43,851
Winchester Lake Gas	0	0	0
Winters Gas	0	0	0

Southern			
Offshore			
Wilmington	0	0	0
Onshore			
Los Angeles Downtown	0	931	0
Prado-Corona	0	0	0
Seal Beach	0	8,687	0
Wilmington	0	0	0
Grand Total	**30,103**	**12,607,293**	**806,210**

2020 SUMMARY OF CALIFORNIA CONDENSATE, NON-ASSOCIATED GAS, AND WATER PRODUCTION

	Condensate Produced (bbl)	Gross Gas Produced (MCF)	Water Produced (bbl)
Coastal			
Onshore	707	76	23,478
Inland			
Onshore	25,676	656,910	510,853
Northern			
Onshore	3,720	11,940,689	271,879
Southern			
Offshore	0	0	0
Onshore	0	9,618	0
Grand Total	**30,103**	**12,607,293**	**806,210**

2020 CALIFORNIA GAS STORAGE BY DISTRICT AND FIELD

	Gas Injected (Mcf)	Gas Withdrawn (Mcf)	Net Gas (Mcf)
Coastal			
Onshore			
Aliso Canyon	23,528,073	18,696,167	4,831,906
Honor Rancho	18,057,674	18,652,038	-594,364
La Goleta Gas	9,656,064	7,421,560	2,234,504
Northern			
Onshore			
Gill Ranch Gas	11,194,296	8,150,290	3,044,006
Kirby Hill Gas	11,199,903	8,651,645	2,548,258
Lodi Gas	11,863,373	9,937,520	1,925,853
Los Medanos Gas	2,495,919	2,437,590	58,329
McDonald Island Gas	28,467,927	18,573,031	9,894,896
Pleasant Creek Gas	0	1,247,659	-1,247,659
Princeton Gas	10,387,231	6,960,561	3,426,670
Wild Goose Gas	46,532,653	35,364,515	11,168,138
Southern			
Onshore			
Playa Del Rey	3,742,987	3,326,246	416,741
Grand Total	**177,126,100**	**139,418,822**	**37,707,278**

2020 CALIFORNIA STEAM AND WATER INJECTION BY DISTRICT AND FIELD

	Cyclic Steam (bbl)	Steamflood (bbl)	Water Disposal (bbl)	Waterflood (bbl)	Total Water Injected (bbl)
Coastal					
Offshore					
Elwood, South, Offshore	0	0	23,619	0	23,619
Onshore					
Aliso Canyon	0	0	338,526	154,262	492,788
Any Field	0	0	16,036,713	0	16,036,713
Arroyo Grande	0	3,069,523	1,246,753	0	4,316,276
Bardsdale	0	0	16,807	5,760	22,567
Barham Ranch	0	0	124,495	0	124,495
Cabrillo	0	0	35,121	0	35,121
Careaga Canyon	0	0	136,502	0	136,502
Cascade	0	0	0	116,933	116,933
Casmalia	0	0	3,377,791	0	3,377,791
Cat Canyon	5,448,166	0	8,548,252	373,927	14,370,345
Cuyama, South	0	0	0	11,673,636	11,673,636
Del Valle	0	0	66,543	0	66,543
Four Deer (ABD)	0	0	75,938	0	75,938
Gaviota Offshore Gas (ABD)	0	0	36,427	0	36,427
Hasley Canyon	0	0	0	36,756	36,756
Holser	0	0	9,367	0	9,367
Honor Rancho	0	0	155,467	0	155,467
Lompoc	0	0	18,606,622	0	18,606,622
Lynch Canyon	121,608	211,577	1,418,338	0	1,751,523
McCool Ranch	0	0	1,929,290	0	1,929,290
Montalvo, West	0	0	346,471	246,906	593,377
Newhall-Potrero	0	0	6,605	0	6,605
Oak Canyon	0	0	80,874	0	80,874
Oak Park	0	0	5,451	0	5,451
Oakridge	0	0	0	667,836	667,836
Ojai	0	0	345,376	0	345,376
Orcutt	1,507,578	0	3,659,730	25,260,431	30,427,739
Oxnard	98,832	0	81,575	0	180,407
Placerita	6,142,085	2,293,436	11,394,347	0	19,829,868
Ramona	0	0	52,033	0	52,033

Rincon	0	0	15,971	1,476,716	1,492,687
Russell Ranch	0	0	0	1,166,675	1,166,675
San Ardo	7,867,192	27,409,479	49,105,015	18,071,986	102,453,672
San Miguelito	0	0	0	2,969,281	2,969,281
Santa Maria Valley	0	0	739,281	237,700	976,981
Sargent	0	0	31,176	0	31,176
Saticoy	0	0	0	50,078	50,078
Sespe	0	0	277,860	0	277,860
Shiells Canyon	0	0	514,119	0	514,119
South Mountain	0	0	0	143,910	143,910
Tapia	0	0	192,496	0	192,496
Temescal	0	0	98,804	0	98,804
Vallecitos	0	0	84,168	0	84,168
Ventura	0	0	0	55,784,197	55,784,197
Zaca	0	0	4,071,447	0	4,071,447
Inland					
Onshore					
Ant Hill	0	0	1,148,641	0	1,148,641
Antelope Hills, North	0	0	375,251	0	375,251
Any Field	0	0	139,870	107,531	247,401
Asphalto	191,063	65,728	811,615	0	1,068,406
Belgian Anticline	0	0	0	25,915	25,915
Bellevue	0	0	224,252	0	224,252
Bellevue, West	0	0	11,664	0	11,664
Belridge, North	20,346	0	238,865	35,085,542	35,344,753
Belridge, South	14,686,958	65,477,012	140,571,844	104,966,905	325,702,719
Blackwells Corner	0	0	41,195	0	41,195
Buena Vista	0	0	9,325,946	30,601,559	39,927,505
Burrel	0	0	922,251	0	922,251
Cal Canal Gas	0	0	91,901	0	91,901
Canal	0	0	1,542	0	1,542
Canfield Ranch	0	0	430,943	0	430,943
Chico-Martinez	7,527	323,827	15,819	0	347,173
Coalinga	15,426,940	26,435,725	3,028,030	10,214,301	55,104,996
Coalinga, East, Extension	0	0	15,334,253	0	15,334,253
Coles Levee, North	0	0	0	17,574	17,574
Coles Levee, South	0	0	53,113	0	53,113
Comanche Point	0	0	532,857	0	532,857
Cymric	44,663,502	21,063,363	858,180	0	66,585,045
Deer Creek	0	0	1,457,740	0	1,457,740
Devils Den	0	0	1,320	0	1,320
Edison	16,839,247	1,002,573	7,413,624	0	25,255,444
Elk Hills	0	0	32,688,616	70,065,993	102,754,609
Fruitvale	84,347	0	8,264,809	109,345	8,458,501

Greeley	0	0	2,447,072	0	2,447,072
Helm	0	0	11,666	0	11,666
Jacalitos	0	0	0	502,268	502,268
Jasmin	0	0	18,150	0	18,150
Kern Bluff	0	0	830,167	0	830,167
Kern Front	349,856	17,664,741	825,102	0	18,839,699
Kern River	7,185,324	48,044,733	11,654,646	0	66,884,703
Kettleman North Dome	0	0	0	1,846,899	1,846,899
Landslide	0	0	0	297,001	297,001
Lost Hills	1,103,656	22,438,261	17,939,405	59,696,330	101,177,652
Lost Hills, Northwest	18,492	0	275,391	0	293,883
McDonald Anticline	0	0	286,667	0	286,667
McKittrick	5,794,151	12,334,894	34,955,689	0	53,084,734
Midway-Sunset	95,009,517	67,129,755	67,607,526	0	229,746,798
Mount Poso	0	0	45,365,419	4,378,366	49,743,785
Mountain View	0	0	241,167	3,885	245,052
Paloma	0	0	18,448	0	18,448
Pleito	0	0	751,599	0	751,599
Poso Creek	5,679,425	26,693,899	130,844,051	276,010	163,493,385
Pyramid Hills	73,359	0	0	150,879	224,238
Raisin City	0	0	905,986	0	905,986
Rio Bravo	119,124	0	0	5,706,722	5,825,846
Rio Viejo	0	0	163,000	0	163,000
Riverdale	0	0	1,100	0	1,100
Rose	0	0	775,081	0	775,081
Rosedale	0	0	4,237	0	4,237
Rosedale Ranch	0	0	3,832,649	0	3,832,649
Round Mountain	132,576	4,229,900	60,733,077	149,385,254	214,480,807
Shafter, North	0	0	1,657,440	0	1,657,440
Tejon	0	0	285,430	5,776,496	6,061,926
Tejon Hills	0	0	133,467	29,604	163,071
Tejon, North	0	0	0	24,539	24,539
Ten Section	0	0	1,569,255	0	1,569,255
Union Avenue	0	0	89,040	0	89,040
Wheeler Ridge	0	0	245,562	11,124	256,686
Yowlumne	0	0	236,166	2,088,714	2,324,880
Northern					
Onshore					
Any Field	0	0	126	0	126
Gill Ranch Gas	0	0	20,298	0	20,298
Grimes Gas	0	0	103,053	0	103,053
Livermore	0	0	23,990	0	23,990
Lodi Gas	0	0	7,824	0	7,824
Rice Creek Gas	0	0	2,040	0	2,040

Rio Vista Gas	0	0	113,866	0	113,866
Sutter City Gas	0	0	56,928	0	56,928
Southern					
Offshore					
Belmont Offshore	0	0	0	11,134,161	11,134,161
Huntington Beach	0	0	0	13,684,087	13,684,087
Wilmington	13,189,033	0	415,995	477,371,104	490,976,132
Onshore					
Beverly Hills	0	0	160,948	2,588,968	2,749,916
Brea-Olinda	0	0	17,802	6,249,157	6,266,959
Cheviot Hills	0	0	10,709	0	10,709
Coyote, East	0	0	0	350,968	350,968
El Segundo	0	0	36,400	0	36,400
Huntington Beach	0	0	0	48,785,745	48,785,745
Inglewood	0	0	0	106,369,607	106,369,607
Las Cienegas	0	0	0	1,822,995	1,822,995
Long Beach	0	0	0	19,224,244	19,224,244
Long Beach Airport	0	0	44,599	0	44,599
Los Angeles Downtown	0	0	0	451,334	451,334
Montebello	0	0	0	17,044,181	17,044,181
Newport, West	0	24,216	0	93,163	117,379
Playa Del Rey	0	0	154,686	0	154,686
Richfield	0	0	0	2,353,548	2,353,548
Rosecrans	0	0	0	595,846	595,846
San Vicente	0	0	0	774,003	774,003
Sansinena	0	0	0	190,966	190,966
Santa Fe Springs	0	0	0	11,810,417	11,810,417
Sawtelle	0	0	0	93,220	93,220
Seal Beach	0	0	0	1,694,863	1,694,863
Torrance	0	0	9,069	4,770,958	4,780,027
Wilmington	2,060,717	0	2,999	255,601,230	257,664,946
Grand Total	**243,820,621**	**345,912,642**	**733,154,498**	**1,582,860,511**	**2,905,748,272**

2020 SUMMARY OF CALIFORNIA STEAM AND WATER INJECTION

	Cyclic Steam (bbl)	Steamflood (bbl)	Water Disposal (bbl)	Waterflood (bbl)	Total Water Injected (bbl)
Coastal	21,185,461	32,984,015	123,285,370	118,436,990	295,891,836
Inland	207,385,410	312,904,411	608,687,796	481,368,756	1,610,346,373
Northern	0	0	328,125	0	328,125
Southern	15,249,750	24,216	853,207	983,054,765	999,181,938
Grand Total	**243,820,621**	**345,912,642**	**733,154,498**	**1,582,860,511**	**2,905,748,272**

2020 OIL, GAS, AND WATER PRODUCTION AND WELL COUNT BY COUNTY

	Well Count		Oil Production	Gas Production			Water Production
County	Active	Inactive*	Oil & Condensate Produced (Bbl)	Associated Gross Gas Produced (Mcf)	Non-Associated Gross Gas Produced (Mcf)	Total GrossGas (Mcf)	Water Produced (Bbl)
Alameda	6	2	3,388	452		452	23,981
Butte	17	5					116
Colusa	156	190			2,232,976	2,232,976	39,365
Contra Costa	21	27	66,944	33,302	83,068	116,370	39,816
Fresno	1,836	1,652	5,754,714	1,145,634		1,145,634	68,907,504
Glenn	185	116			2,065,901	2,065,901	47,093
Humboldt	27	25			350,435	350,435	5,354
Kern	38,202	19,395	103,497,495	115,713,698	656,910	116,370,608	1,792,749,921
Kings	134	213	110,514	193,645		193,645	588,414
Lassen		1					
Los Angeles	2,473	1,839	10,492,774	5,144,131	9,618	5,153,749	439,674,562

Los Angeles Offshore	747	276	8,051,073	3,361,155		3,361,155	454,633,629
Madera	16	13			120,955	120,955	10,723
Merced		2					
Monterey	723	338	7,385,709	1,028,070		1,028,070	150,778,646
Orange	784	486	2,235,856	888,062		888,062	42,690,729
Orange Offshore	63	35	905,852	444,192		444,192	35,167,735
Riverside		3					
Sacramento	73	125	3,504		2,206,285	2,206,285	65,920
San Benito	15	26	10,667	14,607		14,607	1,083
San Bernardino	25	13	7,157	34,740		34,740	797
San Joaquin	127	95			727,405	727,405	34,207
San Luis Obispo	205	135	570,359	539,608		539,608	9,570,677
Santa Barbara	909	1,250	2,625,918	2,157,601	76	2,157,677	77,920,200
Santa Barbara Offshore		26					
Santa Clara	11	14	14,483	13,798		13,798	14,371
Solano	77	133	197		649,194	649,194	20,395
Stanislaus		2					
Sutter	213	192			2,923,932	2,923,932	54,772
Tehama	87	62			565,040	565,040	21,712
Tulare	67	19	25,958				2,218,272
Ventura	1,374	1,580	6,519,070	5,913,061		5,913,061	65,280,360
Ventura Offshore		36	1,067	584		584	312
Yolo	18	52			15,330	15,330	
Yuba	1				168	168	
Total	**48,592**	**28,400**	**148,282,745**	**136,626,341**	**12,607,293**	**149,233,633**	**3,140,560,664**

GEOTHERMAL ENERGY

California is a worldwide leader in geothermal energy generation and the largest producer of geothermal energy in the United States.

Geothermal wells are used to bring hot fluids to the surface where they are used for power generation or for direct use in heating systems, greenhouses, spas, fish farms and other low-temperature applications. High-temperature geothermal wells that produce hot water called geothermal brine or steam usually generate electricity.

California Geothermal Production: Snapshot

There are 2,712 megawatts (MW) of electricity coming from 40 geothermal power plants, enough electricity for about 2.7 million residents according to the California Energy Commission. In 2020, geothermal sources produced 11,345 gigawatt- hours net (GWh), 5.94 percent of the state's power mix. An additional 700 GWh of geothermal power was imported from Nevada.

According to the U.S. Energy Information Administration, geothermal from California is 70 percentof the country's net geothermal power generation that is produced across seven western states including Hawaii.

Number of Wells and Their Locations

There are 563 high-temperature geothermal wells located on state and private lands of which 349 are in The Geysers in Lake and Sonoma Counties and operated primarily by Calpine Corporation. Imperial County is home to 194 wells owned by Cal Energy Operating Corporation, Ormat Technologies Inc., and Energy Source. The remaining 20 wells are scattered in Lassen,Modoc, and Mono counties.

CalGEM's Geothermal Regulatory Role

CalGEM supervises the drilling, operation, maintenance, and plugging and abandonment of high and low-temperature geothermal wells, including injection wells for the discovery and production of geothermal resources in such manner as to safeguard life, health, property, and the public welfare, and to encourage maximum economic recovery (Pub. Resources Code, §§ 3700, 3714.)

Geothermal projects require injection wells so that geothermal fluid, called brine, can be returned to the reservoir after the heat energy has been removed. They are one of approximately 30 types of wells in the Class V program in the Underground Injection Control program of the US EPA. CalGEM does not have primacy, but a memorandum of understanding with Region IX of the US EPA to oversee these injection projects.

Reinjection of geothermal fluids ensures the sustainability of a geothermal reservoir. In some areas, treated effluent from nearby population centers is also injected back into the reservoir for disposal and sustainability of the resource.

The Geysers and Imperial County have kept Kenai Drilling active during the last year. In 2020, CalGEM issued 26 permits for The Geysers and 19 permits in Imperial County. There were 3 low-temperature well permits issued in Riverside County.

Geothermal Assessments

CalGEM's geothermal program is supported by an annual well assessment. The last three years' assessments are as follows:

Fiscal Year	Assessment Amount	Total Wells	$/well
2019/20	$915,726	551	$1662
2020/21	$1,256,002	557	$2255
2021/22	$1,668,169	563	$2963

Geothermal High-Temperature Resources Production and Injection

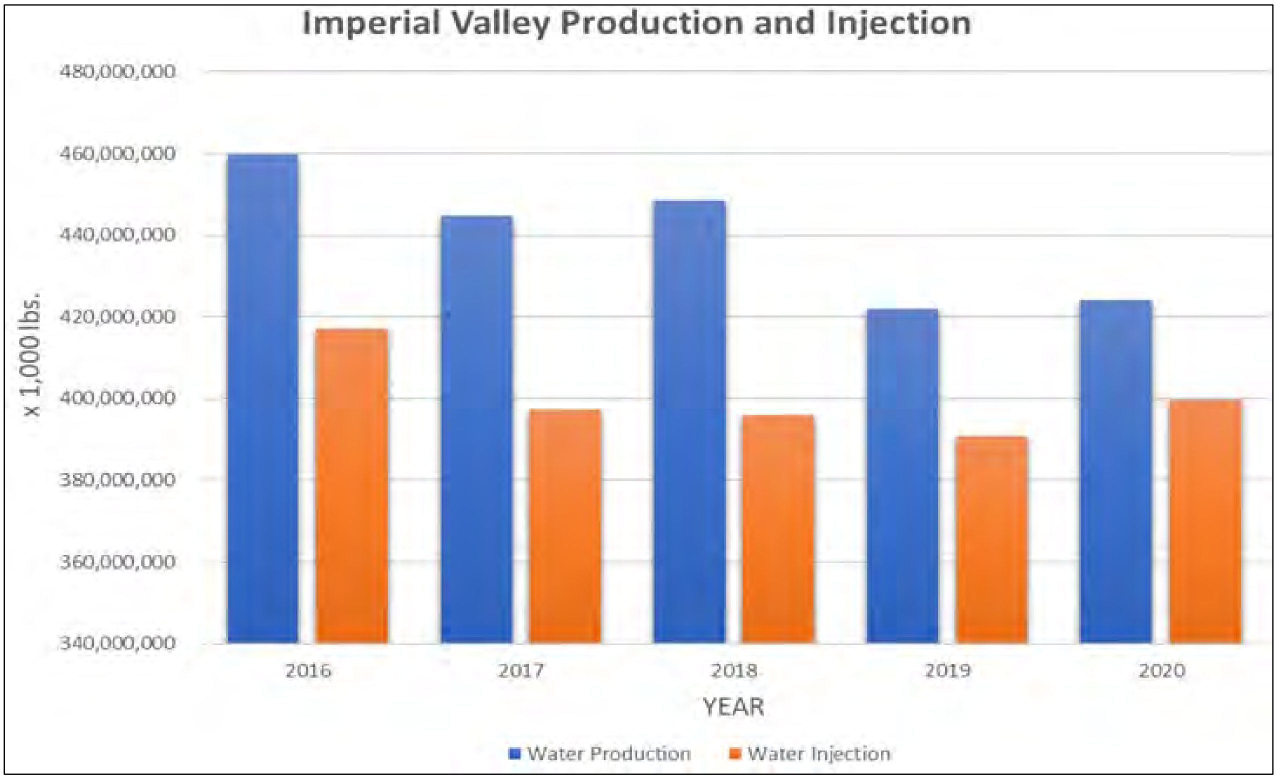


Figure 27: Production and injection in thousands of pounds from high-temperature geothermal wells in Imperial County including the Salton Sea, Brawley, and Heber Fields.

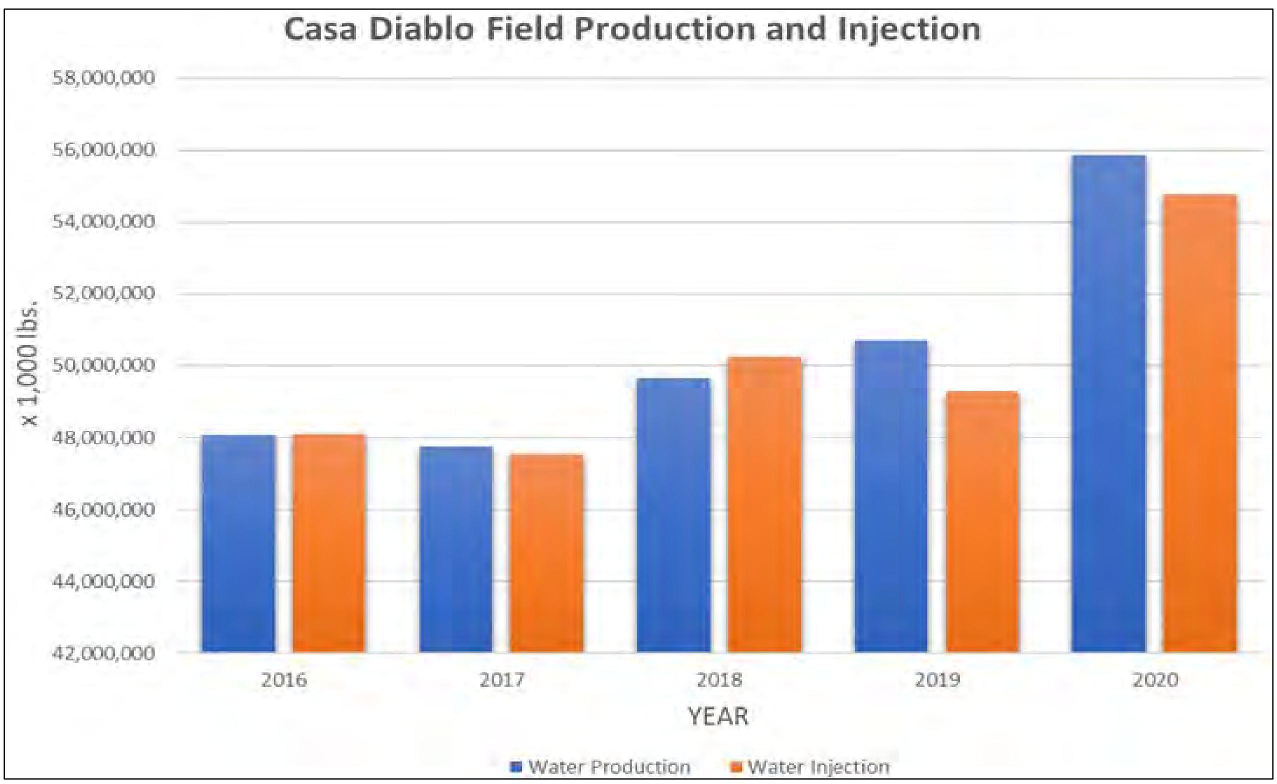


Figure 28: Production and injection in thousands of pounds from high-temperature geothermal wells in Mono County in the Casa Diablo Field near the Town of Mammoth Lakes.

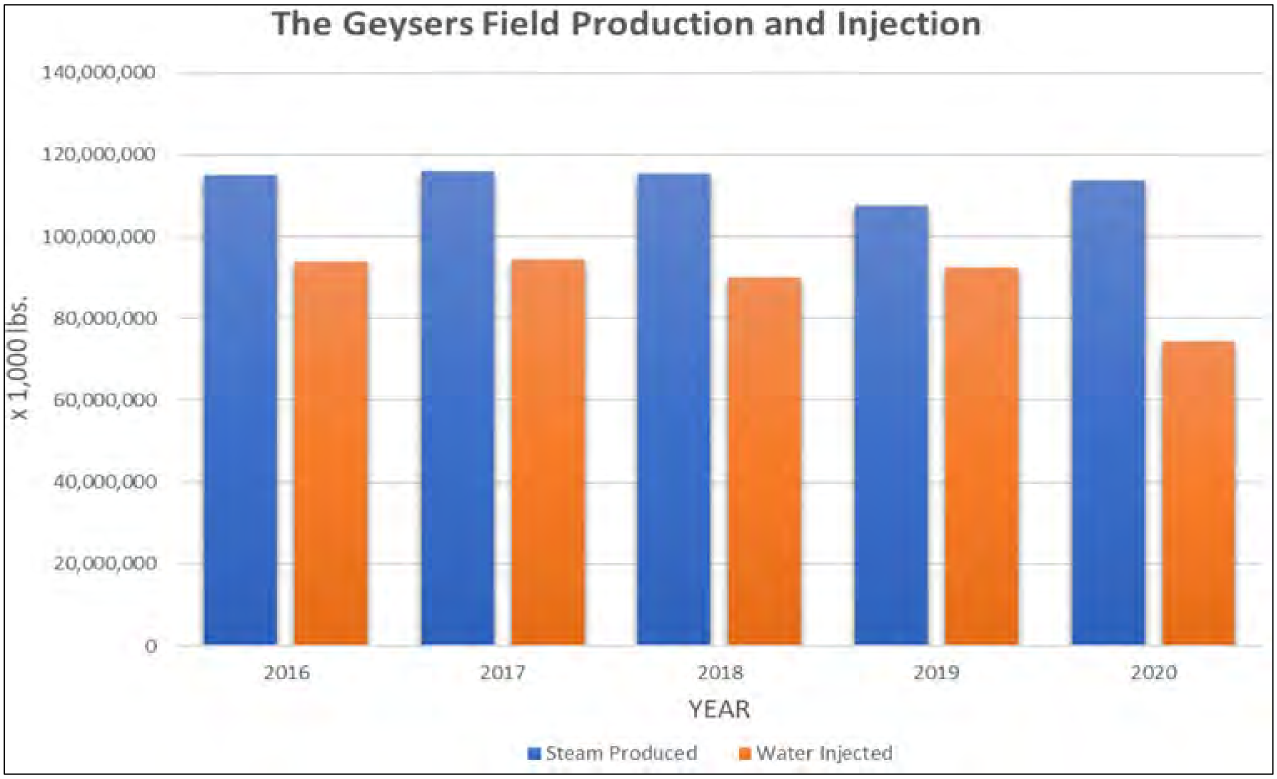


Figure 29: Production and injection in thousands of pounds from The Geysers steam field located in Sonoma and Lake counties. This is the largest producing geothermal field in the world.

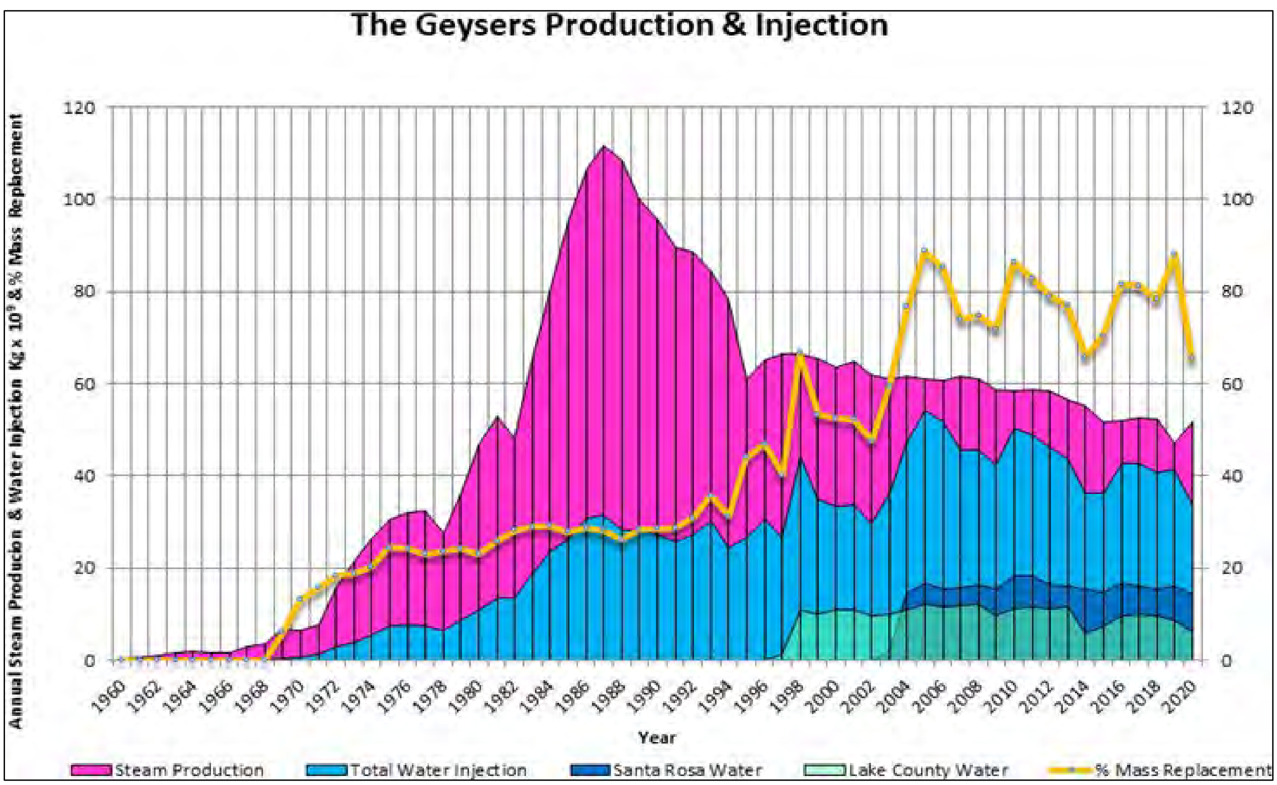


Figure 30: History of production and injection at The Geysers in thousands of kilograms. The field started producing electricity in September 1960.

2020 Production and Injection by Field

Field	Production lbs x 1000	Injection lbs x 1000
Brawley field	19,425,661	21,788,004
Heber field Salton Sea field (2 operators)	138,929,512 267,378,679	153,523,403 226,069,103
Imperial County Total	425,733,851	401,380,509
Casa Diablo Field (Mono County)	55,876,399	54,759,366
The Geysers (Lake and Sonoma)	113,802,678 (steam)	74,388,298
Geothermal Total (lbs. x 1,000)	**595,412,929**	**530,528,174**

Permits by District (Notice of Intention)

	Northern District: The Geysers	Southern District: Imperial & Riverside
Drilling Permits Issued	8	5
Supplemental Permits	5	3
Rework Permits Issued	11	1
Plugging & Abandonment	2	2

Work Completed

	Northern District: The Geysers	Southern District: Imperial & Riverside
Wells Drilled		5*
Wells Reworked	4	11
Plugging & Abandonment	2	1

**3 low temperature wells*

ENFORCEMENT

Background on the Office of Enforcement

The Office of Enforcement was created in July 2019 to facilitate the statewide enforcement of California's oil and gas laws and regulations. The newly formed statewide Enforcement Program takes enforcement actions to prevent damage to life, health, property, and natural resources.

California's PRC provides authority for the Supervisor to order remedial work necessary for the protection of public health and safety and/or the environment, plugging and abandonment orders and civil penalty orders, among others. CalGEM seeks to deter violations and ensure that violators do not receive an unfair business advantage compared to operators who comply with their regulatory obligations. Appropriate penalties for violations attempt to offer assurance of equity between those who comply with regulatory requirements and those who violate them. PRC sections 3236 and 3359 make it a misdemeanor to fail to comply with an order issued by the Supervisor or the oil and gas laws and regulations.

Starting in 2019, CalGEM has been referring such violations to prosecuting agencies. Upon conviction of a misdemeanor, PRC authorizes a fine of not less than one hundred ($100) and not more than one thousand ($1,000), or by imprisonment not exceeding six months, or by both fine and imprisonment for each offense.

Enforcement staff works closely with other CalGEM staff to identify and verify possible violations and take actions to bring violators into conformity with the law and prevent harm. Violations can range from minor issues such as missing records to more significant issues such as failing to perform safety equipment tests, spills, or falsifying records. Enforcement and CalGEM staff assess evidence and the severity of the impacts, and, as appropriate, take corrective measures that can include administrative orders and civil penalties. Depending on the severityof the violation, an operator can be assessed a penalty up to $25,000 per day per incident (geothermal violations are limited to $5,000 per day).

Administrative civil penalties collected from operators are deposited in an Oil and Gas Environmental Remediation (OGER) account. Funds in the OGER account are available for appropriation by the state legislature for plugging and abandoning (permanently sealing) oil and gas wells, decommissioning facilities, or remediating sites that otherwise might pose a danger. The Supervisor has the discretion to permit operators to offset up to 50 percent of assessed penalties on supplemental environmental projects (known as SEPs).

Overview of CalGEM Enforcement Activities 2020	
Inspections	48,488
NOVs	1183
Total Orders Issued	16
P&A	2
Civil Penalties	8
Civil Penalty Fines Issued	$191,669.00
Civil Penalty Received	-
Orders Appealed	2

Field Inspections and Witnessing Operations

Field inspections and witnessing operations are critical oversight functions for CalGEM. In 2020, CalGEM completed 48,488 inspections and witnessed 45,138 shall and may-witness operations across the state.

Shall-witness operations are any that CalGEM is required to witness by law. May-witness operations are any that CalGEM is authorized to witness.

Enforcement Orders

In 2020, CalGEM's Office of Enforcement issued 16 enforcement orders listed below, including $191,669 in civil penalties. The orders issued generally required operators to remediate field violations or otherwise unsafe conditions at their facilities, plug and abandon wells, and/or pay civil penalties. The Supervisor may also issue emergency orders to address a life, health, safety, property, or natural resources concern.

ORDER NO.	ORDER TYPE	OPERATOR	CALGEM DISTRICT	DOCUMENT TITLE	DATE MAILED	CIVIL PENALTY AMOUNT
1160	Plug & Abandonment	Lena Pauline Savage	Southern	Order to Plug and Abandon Wells, Decommission Attendant Facilities, and Restore Well Site	3/11/2020	--
1170	Civil Penalty/Plug& Abandonment	Citadel Exploration, Inc.	Inland	Order to Plug and Abandon Wells, Pay Idle Well Fees, and Pay Civil Penalties	4/10/2020	$12,450
1174	Plug & Abandonment	AllenCo Energy,Inc.	Southern	Order to Plug and Abandon Wells, Decommission Attendant Facilities, And Restore Well Site	3/5/2020	--
1175	Remedial	Pioneer Exploration, LLC	Northern	Order to Perform Remedial Work	4/10/2020	--
1176	Civil Penalty	G.H. Preuitt	Inland	Order to Pay Idle Well Fee and Pay Civil Penalty	5/29/2020	$625
1177	Civil Penalty/Plug& Abandonment	H20-CH4	Northern	Order to Plug and Abandon Well, Pay Idle Well Fees, and Pay Civil Penalties	5/29/2020	$938
1178	Civil Penalty/ Plug & Abandonmen t	Valid Energy Group, Inc.	Inland	Order to Plug and Abandon Wells, Pay Idle Well Fees, and Pay Civil Penalties	6/5/2020	$6,005
1179	Remedial	Century Oil Company	Coastal	Order to Restore Well Site	5/14/2020	--
1180	Civil Penalty/Plug& Abandonment	Caltico Oil Corporation	Coastal	Order to Plug and Abandon Wells, Decommission Attendant Facilities, Restore Well Sites, Pay Idle Well Fees, and Pay Civil Penalties	6/26/2020	$117,032
1181	Civil Penalty	Pioneer Exploration, LLC	Northern	Order to Pay Civil Penalties	10/20/2020	$49,375
1182	Civil Penalty	Dennis C. Franks	Inland	Order to Pay Civil Penalty (Pipeline Management Plan)	10/20/2020	$500

1184	Civil Penalty	C.E. Allen Co	Southern	Order to Pay Civil Penalty (Pipeline Management Plan)	10/30/2020	$500
1185	Civil Penalty	Ballard Oil	Inland	Order to Pay Civil Penalty (Pipeline Management Plan)	12/14/2020	$2,400
1186	Civil Penalty	S&S Oil Company, LLC	Inland	Order to Pay Civil Penalty (Pipeline Management Plan)	12/14/2020	$1,250
1187	Civil Penalty	Undergroun dEnergy, Inc.	Northern	Order to Pay Civil Penalty (Pipeline Management Plan)	12/14/2020	$500
1210	Civil Penalty	Hunt Enterprises	Southern	Order to Pay Civil Penalty (Pipeline Management Plan)	7/23/2020	$500

APPENDIX A: CalGEM Boundaries and Offices

www.conservation.ca.gov

APPENDIX B: Public Resources Code section 3108

On or before the first day of October of each year the supervisor shall make public, for the benefit of all interested persons, a report in writing showing:

(a) The total amounts of oil and gas produced in each county in the state during the previous calendar year.

(b) The total cost of the division for the previous fiscal year.

(c) The total amount delinquent and uncollected from any assessments or charges levied pursuant to this chapter.

The report shall also include such other information as the supervisor deems advisable.

APPENDIX C: Financial Statement for Fiscal Year 2019/2020

(Numbers in Thousands)

3046 OIL, GAS, AND GEOTHERMAL ADMINISTRATIVE FUND	
BEGINNING BALANCE	**5,541**
Prior Year Adjustments	-2451
Adjusted Beginning Balance	3,090
REVENUES	
Assessment fee revenue	102,178
Investment Income	415
Miscellaneous Revenue	
Escheat - Unclaimed checks	2
Total Revenues	**102,595**
Total Resources	**122,984**
EXPENDITURES	
0540 Secretary of the Natural Resources Agency	36
3046 Department of Conservation	78,444
3900 Air Resources Board	2,536
3940 State Water Resources Control Board	15,316
3980 Office of Environmental Health Hazard Assessment	739
8880 Financial Information System for California	0
9892 Supplemental Pension Payment	1,853
9900 Statewide General Administrative Expenditure (Pro Rata)	5,822
Total Expenditures	**104,745**
FUND BALANCE	**940**
0275 HAZARDOUS AND IDLE-DESERTED WELL ABATEMENT FUND	
BEGINNING BALANCE	**10,412**
Prior Year Adjustments	-4
Adjusted Beginning Balance	10,408
REVENUES	
Idle well fees	4,094
Investment Income	190
Total Revenues	**4,284**
Total Resources	**14,692**

EXPENDITURES	
(3046) Department of Conservation	1,588
(9900) Statewide General Administrative Expenditure (Pro Rata)	16
Total Expenditures	**1,604**
FUND BALANCE	**13,088**
0890 FEDERAL TRUST FUND	
UNDERGROUND INJECTION CONTROL	
Total Federal Dollar Expenditures	338
2019 PIPELINES AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION	
Total Federal Dollar Expenditures	1,245
0890 Total	**1,583**

APPENDIX D: Historical List of State Oil & Gas Supervisors

Supervisor	Start Date	End Date
Gabe Tiffany	Jan 2023	current
Uduak-Joe Ntuk	Oct 2019	Jan 2023
Ken Harris	Dec 2015	July 2019
Steve Bohlen	June 2014	Nov 2015
Tim Kustic	Jan 2012	Feb 2014
Elena Miller	Sep 2009	Nov 2011
Hal Bopp	Oct 2003	July 2009
William Guerard Jr.	Jan 1993	Sep 2003
K.P. Hendersen (acting)	Jan 1992	Dec.1992
M. G. Mefferd	1984	Dec 1991
Simon Cordova (acting)	1983	1984
M. G. Mefferd	1977	1983
Harold Bertholf	1976	1976
J.F. Matthews	1971	1975
F.H. Kasline	1968	1970
E.R. Murray-Aaron	1962	1967
E.H. Musser	1954	1961
R.D. Bush	1924	1953
R.E. Collom	1921	1923
R.P. McLaughlin	1915	1920

APPENDIX E: List of Operators Delinquent on First Half Assessments for Calendar Year 2020

	Operator Name	Current Balance
1	Campo Verde Oil, Inc.	$ 213.91
2	Modus, Inc.	$ 892.53
3	Central Pacific Resources	$ 1,121.05
4	El Segundo Oil, LLC	$ 1,478.46
5	Old Field Associates	$ 1,485.77
6	25 Hill Properties, Inc.	$ 342.79
7	Angus Petroleum Corporation	$ 4,394.81
8	Bellaire Oil Company	$ 5,930.44
9	Bruce A. Holmes	$ 1,693.04
10	C & J Oil	$ 223.21
11	C & M Oil Co. & Investments	$ 4,786.80
12	California Hydrocarbons Corporation	$ 444.67
13	California Petroleum Group Inc.	$ 3,854.42
14	Central California Oil Co.	$ 1,538.52
15	Citadel Exploration Inc.	$ 487.94
16	City of Huntington Beach (Fire Dept.)	$ 488.28
17	Coffee Petroleum	$ 909.14
18	Concordia Resources, Inc.	$ 3,261.58
19	D D Natural Resources, LLC	$ 3,834.49
20	DAH Oil LLC	$ 3,143.09
21	Dole Enterprises, Inc.	$ 4,517.75
22	Drilling & Production Co.	$ 6,166.61
23	Elliott Underground LLC	$ 711.83
24	Foothill Energy, LLC	$ 610.00
25	Four Teams Oil Production & Exploration Inc.	$ 1,681.74
26	Fourstar Resources LLC	$ 961.61
27	Gordon Dole	$ 2,570.95
28	Griffin Resources, LLC	$ 9,490.36
29	H.T. Olsen Oil & Gas Operations	$ 1,698.68
30	Havens Oil Company	$ 25.91
31	HVI Cat Canyon, Inc.	$ 66,833.06
32	J & K Operating Company, Inc.	$ 763.98
33	J.P. Oil Company, LLC	$ 35,455.40
34	Jean Martinez	$ 142.16

35	Kelpetro Operating, Inc.	$	1,150.94
36	Kern River Holdings II, LLC	$	164,406.30
37	Morrison Oil Co., LLC	$	736.42
38	New Opportunity Exploration, Inc.	$	499.25
39	O'Donnell Oil, LLC	$	13,011.48
40	Optima Conservation Resources Exploration, LLC	$	1,121.39
41	P. C. Oil Company	$	384.64
42	Padre Oil Co.	$	378.66
43	Petroprize	$	960.95
44	Pioneer Exploration, LLC	$	8,531.18
45	PowerDrive Energy Services Company, LLC	$	8,738.45
46	PRE Resources, LLC	$	4,931.59
47	R&R Resources, LLC	$	832.07
48	Rountree/Wright Enterprises, LLC	$	797.19
49	S & C Oil Co., Inc.	$	14,930.92
50	Salt Creek Oil LLC	$	3,429.75
51	Sherman Havens	$	355.09
52	Source Energy Corp.	$	1,134.50
53	Summit Energy, LLC	$	2,678.23
54	Sun Mountain Oil & Gas	$	1,215.05
55	Thompson Energy Resources, LLC	$	1,528.95
56	TJ Scott Family Investments, LLC	$	1,439.60
57	Towne Exploration Company, LP	$	471.67
58	Wilco-Placentia Oil Operator LLC	$	25,962.88
59	William H. Fisk	$	75.33
60	Hoyt Energy, L.L.C.	$	470.45
61	Bennett Petroleum, Inc.	$	753.85
62	Berry Petroleum Company, LLC	$	36,311.31
63	Black Gold Oil Company	$	127.32
64	Brindle/Thomas	$	1,159.96
65	Caleco, LLC	$	4,076.94
66	Case's Used Equipment	$	111.19
67	CMO, Inc.	$	3,989.33
68	Duncan's Pumping Service	$	295.50
69	John A. Thomas	$	11,258.86
70	Matrix Oil Corporation	$	1,813.78
71	Naftex Operating Company	$	39,267.13
72	Reef Ridge Energy Company LLC	$	202.16
73	Renaissance Petroleum, LLC	$	1,349.59
74	Thomas Oilers	$	377.78
75	West Coast Operators Inc.	$	248.48
	TOTAL	**$**	**538,546.27**

CALIFORNIA GEOLOGIC ENERGY MANAGEMENT DIVISION

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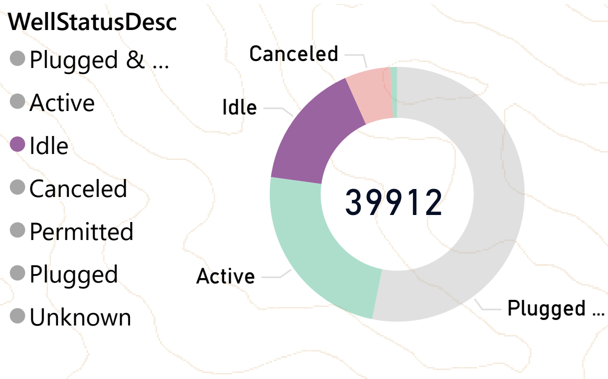
Well Information

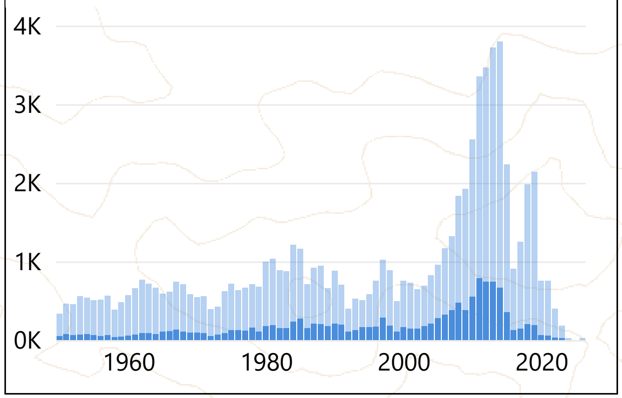
By Well Type | By Well Status

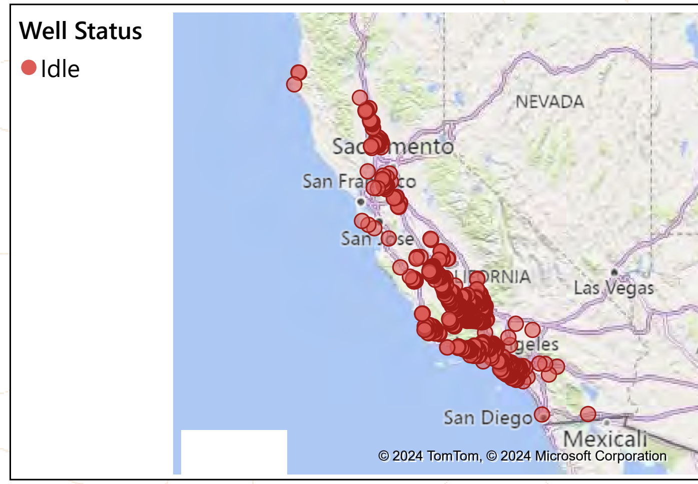
Well Status Count



By Spud Date | By Status Change Date

Well Count by Spud Date





Well Finder	Well Record Request	Well API	Well Designation	Well Type	Well Status	Operator	Lease Name
		0400100007	1	Dry Hole	Idle	Brady Sure Shot Oil Co.	Unspecified
		0400700010	T. W. Rodgers 1	Dry Gas	Idle	Harvest Petroleum, Inc.	T. W. Rodgers
		0400700011	Wahl Comm. 1	Dry Gas	Idle	Harvest Petroleum, Inc.	Wahl Comm.
		0400720008	Wahl Comm. 2	Dry Gas	Idle	Harvest Petroleum, Inc.	Wahl Comm.
		0400720028	Newby Durham Unit 1	Dry Gas	Idle	Harvest Petroleum, Inc.	Newby Durham Unit
		0400720066	Newby Durham Unit 2	Dry Gas	Idle	Harvest Petroleum, Inc.	Newby Durham Unit
		0401100020	A.S. Wiggin 1	Dry Gas	Idle	California Resources Production Corporation	A.S. Wiggin
		0401100033	Arbuckle Unit M 1	Dry Gas	Idle	California Resources Production Corporation	Arbuckle Unit M
		0401100034	Arbuckle Unit N 1	Dry Gas	Idle	California Resources Production Corporation	Arbuckle Unit N
		0401100039	Arbuckle Unit W 1	Dry Gas	Idle	California Resources Production Corporation	Arbuckle Unit W

SB 1137 FIRST EMERGENCY IMPLEMENTATION REGULATIONS

NOTICE OF PROPOSED EMERGENCY RULEMAKING ACTION

REGARDING

CALIFORNIA CODE OF REGULATIONS
TITLE 14. NATURAL RESOURCES
DIVISION 2. DEPARTMENT OF CONSERVATION
CHAPTER 4. DEVELOPMENT, REGULATION, AND CONSERVATION OF OIL AND GAS RESOURCES
SUBCHAPTER 2. ENVIRONMENTAL PROTECTION

Notice Published December 19, 2022

NOTICE IS HEREBY GIVEN that the California Department of Conservation (Department) proposes to adopt emergency regulations necessary to protect public health, safety, and the environment, by ensuring the immediate implementation of health protection zones for all oil and gas operations in the state that are near sensitive receptors. This action is being taken in accordance with Government Code sections 11346.1 and 11349.6 of the California Administrative Procedure Act.

These regulations will be submitted to the Office of Administrative Law (OAL) on December 28, 2022, with an intended effective date no later than January 7, 2023.

Government Code section 11346.1, subdivision (a)(2), requires that, at least five working days prior to submission of a proposed emergency action to OAL, the adopting agency provide a notice of the proposed emergency action to every person who has filed a request for notice of regulatory action with the agency. After submission of the proposed emergency action to OAL, OAL shall post the notice of proposed emergency action on its website and allow interested persons five calendar days to submit comments on the proposed emergency regulations, as set forth in Government Code section 11349.6.

PUBLIC COMMENT

If you wish to comment on the proposed emergency action, please submit your comment directly to both OAL and the Department within five calendar days of OAL's posting of the proposed emergency regulations on the OAL website. You may submit comments to OAL and the Department at the following addresses:

OAL Reference Attorney
300 Capital Mall, Suite 1250
Sacramento, CA 95814
staff@oal.ca.gov

Department of Conservation
715 P Street, MS 1907
Sacramento, CA 95814
Attn: SB 1137 Health Protection Zones
calgemregulations@conservation.ca.gov

OAL will confirm that the Department has received each comment before considering it. Pursuant to California Code of Regulations, title 1, section 55, subdivision (b)(1) through (4), the comment must state that it is about an emergency regulation currently under OAL review, and include the topic of the emergency.

Adoption of emergency regulations does not require response to submitted comments. Where responses are issued by the Department, they will be submitted to OAL within eight calendar days following the date of submission of the proposed emergency regulations to OAL, unless specific exceptions are applicable.

FINDING OF EMERGENCY

Government Code section 11346.1, subdivision (b), allows a state agency to adopt emergency regulations if the agency makes a finding that the adoption of a regulation is necessary to address a situation calling for immediate action to avoid serious harm to the public peace, health, safety, or general welfare. The Department finds that emergency adoption of the regulations proposed herein regarding health protection zones is necessary for immediate preservation of the public peace, health, safety, or general welfare.

Basis for the Finding of Emergency:

Senate Bill 1137 (Gonzalez, Chapter 385, Statutes of 2022) adds Article 4.6, titled "Health Protection Zones," to Chapter 1 of Division 3 of the Public Resources Code. Article 4.6 includes an express legislative declaration that adoption of regulations to implement the provisions of the new article shall, for purposes of the Administrative Procedure Act, be considered an "emergency" necessary for the immediate preservation of public peace, health, and safety. Further, the Legislature authorized the Department, through its Geologic Energy Management Division (CalGEM), to employ emergency rulemaking procedures to address that need. The declaration and finding appear in Public Resources Code section 3288:

> The division, the State Air Resources Board, and the State Water Resources Control Board may prescribe, adopt, and enforce any emergency regulations as necessary to implement, administer, and enforce its duties under this article. Any emergency regulation prescribed, adopted, or enforced pursuant to this article shall be adopted in accordance with Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code, and, for purposes of that chapter, including Section 11349.6 of the Government Code, the adoption of the regulation is an emergency and shall be considered by the Office of Administrative Law as necessary for the immediate preservation of the public peace, health and safety, and general welfare. Notwithstanding any other law, the emergency regulations adopted by the division, the State Air Resources Board, and the State Water Resources Control Board may remain in effect for two years from adoption.

Within section 1 of Senate Bill 1137, the Legislature also made the following findings and declarations:

- "In addition to increasing impacts of climate change, a growing body of research shows direct health impacts from proximity to oil extraction."
- "These impacts are disproportionately impacting Black, indigenous, and people of color in California, who are most likely to live in close proximity to oil extraction activities and who are the most vulnerable to the negative impacts of climate change."
- "Proximity to oil and gas extraction sites pose significant health risks, especially due to increased air pollution."
- "Studies have shown evidence of harm at distances less than one kilometer, which is approximately 3,200 feet."
- "Further assistance must be provided to frontline communities that have been most polluted by the fossil fuel industry by cleaning up pollution, remediating negative health impacts, and building resilient infrastructure to prepare for the unavoidable impacts of climate change."

AUTHORITY AND REFERENCE

Pursuant to the authority vested by sections 3011, 3013, 3106, 3270, and 3288 of the Public Resources Code, and to implement, interpret, or make specific sections 3011, 3106, 3203, 3270, 3280, 3281, 3281.5, 3284, 3285, 3288, and 3403.5 of the Public Resources Code, the Department is proposing changes to Subchapter 2 of Chapter 4 of Division 2 of Title 14 of the California Code of Regulations as follows: the addition of Article 2.5, consisting of sections 1765, 1765.1, 1765.2, 1765.3, 1765.4, 1765.4.1, 1765.5, 1765.5.1, 1765.6, 1765.7, 1765.8, 1765.9, and 1765.10.

INFORMATIVE DIGEST / POLICY STATEMENT

Existing Law

CalGEM regulates the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil and gas wells, and the operation, maintenance, and removal or abandonment of facilities attendant to oil and gas production throughout California. CalGEM carries out this regulatory mission under a legislative mandate to encourage the wise development of oil and gas resources, while preventing damage to life, health, property, and natural resources, including underground and surface waters suitable for domestic or irrigation purposes. (Pub. Resources Code, § 3106.) CalGEM's duties include the protection of public health and safety and environmental quality, including reduction and mitigation of greenhouse gas emissions associated with the development of hydrocarbon resources. (Pub. Resources Code, § 3011.) Written notice to and approval from CalGEM is required before any oil or gas well may be drilled, redrilled, deepened, plugged and abandoned, or subjected to any operations permanently altering the casing of the well. (Pub. Resources Code, § 3203.) The process for providing that notice to CalGEM is referred to as a "notice of intention."

In furtherance of these legislative mandates, CalGEM oversees and enforces compliance with numerous existing statutory and regulatory requirements regarding oil and gas operations in California. These include: requirements regarding the protection of underground and surface water, requirements for testing and monitoring to ensure the integrity of the well casing, requirements for cement used to secure the well casing inside the bore hole, requirements for the cement and equipment used to seal off the well from other hydrocarbon resources and groundwater resources, requirements for routinized reporting of information about production and injection volumes, and minimum maintenance requirements for oil and gas production facilities. Compliance with and enforcement of these requirements provides a first line of protection from potential damage caused by oil and gas production.

On September 16, 2022, Governor Gavin Newsom signed into law Senate Bill 1137 (Gonzalez, Chapter 365, Statutes of 2022) (SB 1137). SB 1137 complements and expands upon this existing framework by creating Health Protection Zones in a 3,200-foot area around "sensitive receptors," as defined in the bill. SB 1137 sets forth a variety of new requirements related to Health Protection Zones and to wells and production facilities based on their location relative to a Health Protection Zone. Some of these requirements do not take effect until 2025 or 2027. Several new requirements, however, involve compliance obligations commencing in 2023. Beginning on January 1, 2023, CalGEM will no longer be authorized to approve a notice of intention for any well with a wellhead (i.e., a surface location) situated within a Health Protection Zone, unless a specific exception applies. Further, beginning January 1, 2023, when performing work authorized by an approved notice of intention on a well located within a Health Protection Zone, operators will be required to offer sampling and testing of water wells and surface water to nearby property owners and tenants, and to provide related notices and information to certain state agencies. Construction and operation of new production facilities within a Health Protection Zone also will be statutorily prohibited as of January 1, 2023, unless a specific exception applies. Additionally, beginning July 1, 2023, all operators of oil and gas wells in California will be required to provide CalGEM with an annual submission that describes the proximity of their wells and production facilities to sensitive receptors.

Objectives and Benefits of the Emergency Regulations

This emergency rulemaking is intended to interpret and make specific certain provisions of the Public Resources Code as necessary to implement those particular statutory imperatives regarding Health Protection Zones that take effect in 2023, pursuant to SB 1137.

More specifically, the proposed language of the emergency regulations will accomplish the following:

- **Proposed section 1765. "Scope and Purpose."** This section describes and clarifies the intended function of all the regulations within the newly created Article 2.5.

- **Proposed section 1765.1. "Definitions."** This section specifies and clarifies aspects of the definition of "sensitive receptor," as provided in Public Resources Code section 3280, subdivision (c). In particular, this section provides specifications regarding what constitutes a "community resource center," what constitutes a "business that is open to the public," and what qualifies a "park" to be a type of "education resource," for purposes of identifying sensitive receptors. This specification is necessary to set consistent expectations on establishing Health Protection Zones, the related compliance status of operators, and any subsequent enforcement. This section also duplicates the statutory definition of "sensitive receptor" found in Public Resources Code section 3280, subdivision (c). This duplication is necessary to give contextual clarity to its specifications of the "sensitive receptor" definition.

- **Proposed section 1765.2. "Measuring Distances."** This section specifies standards or procedures applicable to several types of measurements called for elsewhere within the proposed regulations. This specification is necessary to ensure consistency in methods, reported data, and the determinations based on those data.

- **Proposed section 1765.3. "Additional Requirements for a Notice of Intention."** This section specifies the additional informational items an operator must provide in connection with a notice of intention in order for CalGEM to determine whether it may approve the notice of intention, consistent with the general statutory prohibition and specific exceptions applicable to approval of notices of intention within a Health Protection Zone. The additional informational items include data and information needed to determine the location of the well at issue relative to any proximate Health Protection Zone, and information needed to evaluate if the notice of intention may be necessary to prevent or respond to a threat to public health, safety, or the environment. This specification is necessary to ensure notices of intention contain the information necessary for CalGEM's approval determination.

- **Proposed sections 1765.4, "Water Sampling and Testing," and 1765.4.1, "Notice to Property Owners and Tenants."** Public Resources Code section 3284 requires that operators offer to provide testing of water wells or surface water to property owners and tenants within a Health Protection Zone when the operator performs work authorized by an approved notice of intention on a well located in the Health Protection Zone. Public Resources Code section 3284 further requires operators to provide notice to certain state agencies before conducting the water sampling and to submit the water quality data obtained as a result of that testing to certain state agencies. Public Resources Code section 3284 also authorizes a waiver of the water sampling and testing requirements in certain situations. This section specifies procedures for operators to complete and document compliance with these statutory requirements and clarifies what information an operator would need to provide to CalGEM if seeking a waiver. These sections are necessary to provide operators with a clear and consistent direction for compliance with the notification requirements of Public Resources Code section 3284, to ensure that CalGEM receives consistent, sufficiently detailed documentation of compliance from operators to enable effective enforcement oversight, and to clarify the information CalGEM will need operators to provide for its consideration when seeking a waiver from the water sampling and testing requirements.

- **Proposed sections 1765.5, "Required Notice for New Production Facilities," and 1765.5.1, "Contents of a New Production Facility Notice."** Public Resources Code section 3281, subdivision (b), prohibits the construction or operation of a new production facility within a Health Protection Zone, unless subject to certain exceptions. Section 1765.5 specifies a notice procedure required before an operator constructs or operates a new production facility. This section also clarifies the procedure by which CalGEM will evaluate such notices to confirm that the new production facility may be constructed or operated in compliance with the requirements of Public Resources Code section 3281, subdivision (b). Section 1765.5.1 specifies the informational contents of the "new production facility notice" referenced in section 1765.5's notice procedure. Sections 1765.5 and 1765.5.1 are necessary so that CalGEM will consistently receive timely prior notice and sufficient information to effectively enforce compliance with the general prohibition and specific exceptions applicable to construction and operation of new production facilities within a Health Protection Zone.

- **Proposed section 1765.6, "Annual Submission of Sensitive Receptor Inventory and Map."** This section specifies the informational contents that an operator must include in the annual submission describing the proximity of its wells and production facilities to sensitive receptors, as required under Public Resources Code section 3285. This section is necessary to provide operators with clear direction for compliance and to ensure that the annual submission information CalGEM receives is sufficiently complete and consistent in content. Complete and consistent annual submission information will facilitate CalGEM's timely and orderly enforcement of compliance with requirements related to Health Protection Zones.

- **Proposed sections 1765.7, “Content and Format Specifications for Sensitive Receptor Inventories,” and 1765.8, “Content and Format Specifications for Sensitive Receptor Maps.”** As part of the process for identifying Health Protection Zones and enforcing requirements related to Health Protection Zones, Public Resources Code sections 3281 and 3285 require that operators submit inventories and maps of sensitive receptors to CalGEM annually, with respect to all of the operator’s wells and production facilities, and also when seeking approval of a notice of intention, with respect to the particular well or wells that are the subject of the notice. The inventories and maps are the core informational materials required from operators to confirm whether wells and production facilities are located within a Health Protection Zone. Sections 1765.7 and 1765.8 specify the content and format of the required inventories and maps, with distinctions based on the submission requirement the map and inventory are intended to satisfy. These sections are necessary to ensure that when CalGEM receives this information about sensitive receptors, wells, and production facilities it is sufficiently complete, organized, and in a usable format. Complete, organized, readily usable inventory and mapping information will be essential for CalGEM to review notices of intention, new production facility notices, and annual sensitive receptor submissions in a timely manner, to enable CalGEM’s effective enforcement of compliance with requirements related to Health Protection Zones, and to facilitate provision of information to interested members of the public.

- **Proposed section 1765.9, “Determination that a Location is Not Within a Health Protection Zone.”** This section specifies the process and informational requirements applicable when an operator seeks to demonstrate that a well, production facility, or part or all of their operations are not within the boundaries of a Health Protection Zone. Determination that a location is not within a Health Protection Zone is a component of the procedures for notices of intention, new production facility notices, and annual sensitive receptor inventory and map submissions set forth in other sections of the proposed regulations. Those other sections include a cross-reference to this section. Consequently, this section is necessary to clarify how the determination will be made and to ensure that the information CalGEM receives in this context is consistent and sufficiently complete.

- **Proposed section 1765.10, “Underground Gas Storage Facilities in the Health Protection Zone.”** Public Resources Code section 3181 expressly excludes underground gas storage wells and attendant production facilities from compliance with the various requirements related to Health Protection Zones. This section clarifies the scope of that exclusion.

CONSISTENCY WITH FEDERAL REGULATION OR STATUTE

The proposed regulations are an administrative framework for implementing specific and express requirements of SB 1137 and certain related statutes. The proposed regulations are not inconsistent or incompatible with federal statutes and regulations.

CONSISTENCY WITH EXISTING STATE REGULATIONS

The proposed regulations are an administrative framework for implementing specific and express requirements of SB 1137 and certain related statutes. No other state agency has existing regulations implementing SB 1137. The proposed regulations are intended to dovetail with existing requirements implemented by other state agencies charged with regulatory functions related to natural resources, the environment, and public health, such as the State Water Resources Control Board and the regional water quality control boards. The proposed regulations are not inconsistent or incompatible with existing state regulations.

LOCAL MANDATE

The proposed regulations do not impose a mandate on local agencies or school districts.

COST OR SAVINGS TO STATE AGENCIES

Costs or Savings to State Agencies: Impacts on the Department will be limited to costs associated with administration and review of operator submission.

Non-Discretionary Costs or Savings to Local Agencies, Including Costs to any Local Agency or School District Requiring Reimbursement Pursuant to Section 17500 *et seq.:* There will be no impact on local agencies.

Costs or Savings in Federal Funding to the State: There will be no impact on federal funding to the state.

DOCUMENTS RELIED UPON

The Department relied upon the following documents in proposing this rulemaking action:

- Senate Bill 1137, Gonzalez, Chapter 365, Statutes of 2022.
- Dill, J. (2003). Transit use and proximity to rail: Results from large employment sites in the San Francisco, California, Bay Area. *Transportation Research Record*, *1835*(1), 19-24.
- Dittmar, H., and G. Ohland, eds. (2004). The New Transit Town: Best Practices in Transit-Oriented Development. Island Press. p. 120.

AVAILABILITY OF DOCUMENTS ON THE INTERNET

The proposed regulatory language for the emergency regulations can be accessed through our website at: https://www.conservation.ca.gov/index/Pages/rulemaking.aspx.

If you have questions regarding the process of the proposed emergency action, please contact Glen Baird, Office of Legislative and Regulatory Affairs at (916) 531-7201 or calgemregulations@conservation.ca.gov.

Well Inspections & Repair Updates

Repair Work is Complete

Repairs for these wells were completed May 17, 2023. Refer to the timeline below for details on the work. *Leer versión español*.

Update Archive

May 17, 2023

May 5, 2023

April 25, 2023

April 7, 2023

March 29, 2023

March 3, 2023

March 1, 2023

February 3, 2023

January 20, 2023

December 5, 2022

November 8, 2022

October 28, 2022

October 24, 2022

October 12, 2022

October 5, 2022

October 3, 2022

September 15, 2022

August 19, 2022

August 12, 2022

July 22, 2022

July 19, 2022

As of today, 38 wells previously found to have methane leaks or high pressure build-up have been repaired. CalGEM remains committed to conducting ongoing post-repair inspections of the wells to confirm all leaks are properly fixed.

CalGEM continues to work with Griffin Resources, LLC to properly fix one well that was found to be leaking methane after initial repair work. CalGEM has also retained a contractor to repair the eight wells owned by Citadel Exploration Inc. that were previously found to be leaking elevated concentrations of methane. In order to expedite the repairs to the Citadel wells, CalGEM i using its discretionary funds to pay for the contractor, but will seek all options for cost recovery from the operator once work is completed. So far, the contractor has repaired four of the eight

Citadel wells.

A summary of the status of the wells by operator can be found below:

- **Griffin Resources, LLC wells in the Fruitvale oil field**
  Fourteen wells were previously found to be leaking methane. Repairs were undertaken on all fourteen wells; however, one of those wells continues to leak low levels of methane. CalGEM is working with the operator to properly repair the remaining leaking well.
- **Sunray Petroleum wells in the Kern Bluff oil field**
  All six wells previously found to be leaking methane are repaired. Post-repair inspections show no methane leakage.
- **Zynergy, LLC wells in the Kern Bluff oil field**
  All seven wells previously found to be leaking methane are now repaired. Post-repair inspections show no methane leakage.
- **Citadel Exploration Inc. wells in the Kern Bluff oil field**
  Eight wells were previously identified with methane leaks. CalGEM's contractor has begun work to stop the leaks on these wells – as of today, four of the eight wells have been repaired.

  Seven of these eight wells are included in a CalGEM-issued Order to Plug and Abandon Wells, Pay Idle Wells Fees and Pay Civil Penalties. Citadel failed to comply with the Order in a timely manner. As a result, CalGEM has filed a petition for a court order directing payment of the civil penalty, compliance with CalGEM's earlier plug and abandonment order, and discontinuing production until all violations have been remedied and the civil penalty paid.
- **E&B Natural Resources wells in the Fruitvale oil field**
  All eight wells previously identified to have high pressure build-up within the well, including one which also had a methane leak, have been fixed. Post-repair inspections show no methane leakage and low pressures.

July 8, 2022

June 25, 2022

June 17, 2022

June 16, 2022

June 7, 2022

June 4, 2022

June 1, 2022

May 31, 2022

May 27, 2022 Community Forums

May 26, 2022

May 25, 2022

May 20, 2022

Actualización sobre los pozos inactivos de Bakersfield

Health & Air Pollution

CATEGORIES

Topics Health, Indoor Air Quality & Exposure, Research, Environmental Justice, Sustainable Communities, Airborne Toxics, Air Pollution, Air Quality Monitoring

Programs Outdoor Air Quality Standards, People at Risk, Exposure, Community Air Protection Program

Type Information

CONTACT

Research Division

Email research@arb.ca.gov

Phone (916) 445-0753

Air pollution continues to be an important public health concern. A number of air pollutants, coming out of a variety of industrial processes, impact the health of California residents. Air monitoring shows that over 90 percent of Californians breathe unhealthy levels of one or more air pollutants during some part of the year. The California Air Resources Board (CARB) establishes health-based ambient air quality standards to identify outdoor pollutant levels that are considered safe for the public - including those individuals most sensitive to the effects of air pollution, such as children and the elderly.

CARB has set standards for eight "traditional pollutants," such as ozone and particulate matter. In addition to setting standards, CARB identifies other air pollutants as toxic air contaminants (TACs) - pollutants that may cause serious, long-term effects, such as cancer, even at low levels. Most air toxics have no known safe levels, and some may accumulate in the body from repeated exposures. CARB has identified about 200 pollutants as air toxics, and measures continue to be adopted to reduce emissions of air toxics. Estimated total cancer risk from all air toxics is 730 per million. Of this total, 520 per million are due to diesel particulate matter.

If PM2.5 were reduced to background levels, estimated health impacts avoided per year would be:

- 7,200 premature deaths
- 1,900 hospitalizations
- 5,200 emergency room visits

Similarly, if diesel particulate matter were removed from the air, estimated yearly health impacts would be:

- 1,400 premature deaths
- 200 hospitalizations
- 600 emergency room visits

Both traditional pollutants and toxic air contaminants are measured statewide to assess programs for cleaning the air. CARB works with local air pollution control districts to reduce air pollution from all sources.

Climate change will also pose risks to public health. Changes in our climate are leading to extreme high temperatures which could result in more heat-related sickness and deaths, increased allergens (such as pollen) will trigger worsened allergies, and increases in disease-carrying mosquitoes and other pests will cause elevated disease risk.

More information about common air pollutants and their health effects can be found at: https://ww2.arb.ca.gov/resources/common-air-pollutants

RELATED RESOURCES

Collaborating with Communities to Find Ways to Cope with Heat and Reduce Health Impacts

Determining energy use patterns and battery charging infrastructure for zero-emission heavy-duty vehicles and off-road equipment

Impacts of toxic air contaminants from residential appliances

(800) 242-4450 | helpline@arb.ca.gov
1001 I Street, Sacramento, CA 95814
P.O. Box 2815, Sacramento, CA 95812

The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California and How to Clean them Up!

- Largest number of refineries in state are concentrated in the Wilmington area
- Wilmington's rising impacts from fossil fuels, (ports, oil drilling, diesel trucking, highway expansions, more) are unaddressed by public policy
- Dirty Crude Oil use by refineries is increasing local, regional, and global pollution

Solutions are available that create jobs:

- Best Available Control Technology
- Cap on dirty crude oil
- Phaseout fossil fuels in favor of alternatives
- Cumulative Impact policies

COMMUNITIES FOR A BETTER ENVIRONMENT — APRIL 2009

The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California

Principal Author
Julia May, Senior Scientist, CBE
With contributions and review from Adrienne Bloch, Bahram Fazeli, Jennifer Ganata, Will Gordon, Greg Karras, Sarah Kern, Shana Lazerow, Yuki Kidokoro, and Jesus Torres

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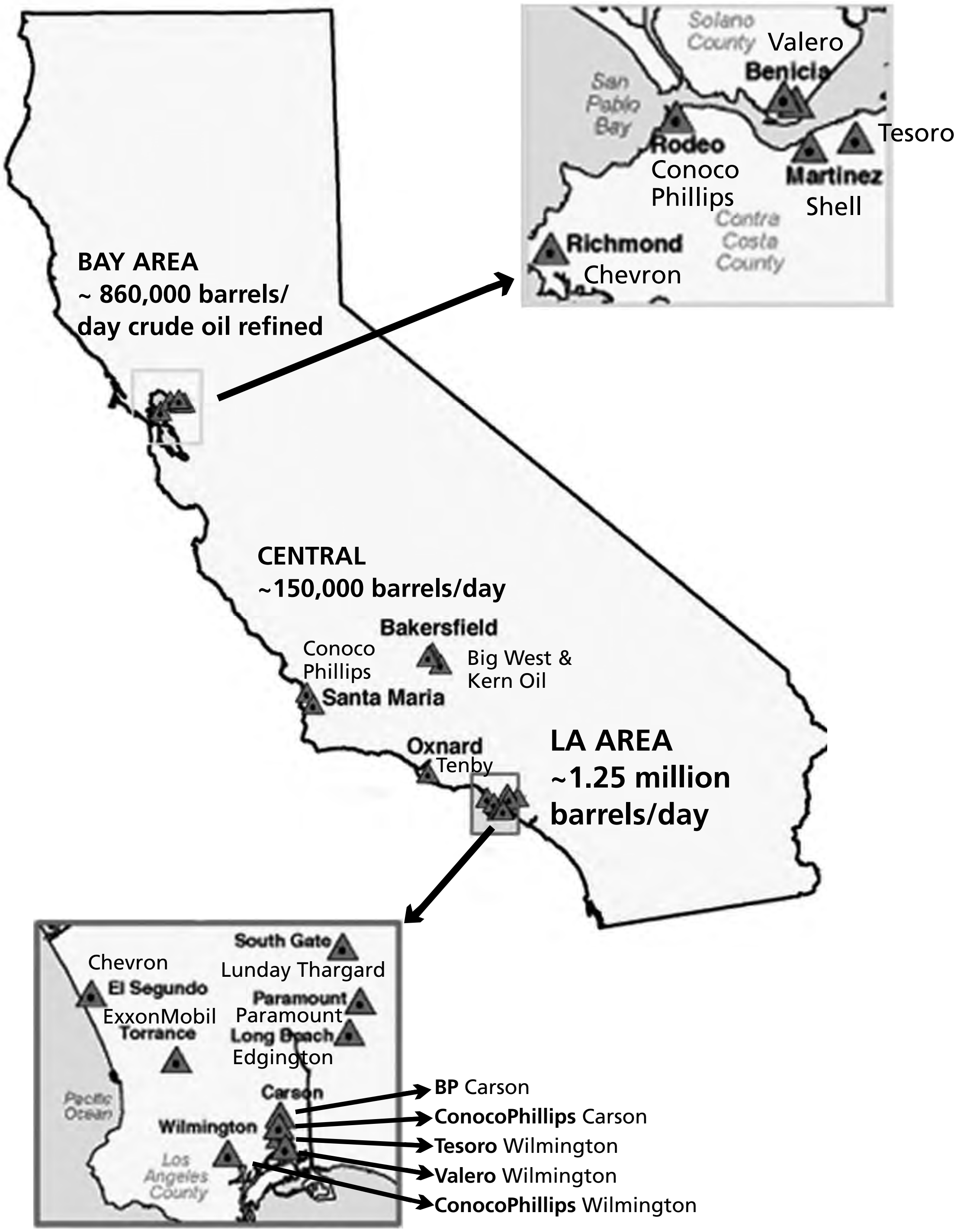
Communities for a Better Environment (CBE)
Headquarters: 5610 Pacific Blvd., Suite 203, Huntington Park, CA 90255

Contents

Many areas of California are heavily impacted by oil refineries[1], but Wilmington/Carson has the highest concentration of refineries statewide.



Executive Summary

This report looks at the impacts of the refining industry on California health and the environment, and how processing dirtier crude oil seriously exacerbates existing problems, using the case of the heavily-burdened Wilmington/Carson area in Southern California. We compile basic crude oil quality information and associated air emissions. The Wilmington/ Carson area in Southern California emerges with the highest concentration of refineries in California (see map to left), with a surprising 650,000 barrels per day of crude oil processing (about a **third** of the state's production, and half of LA-area refinery VOC's).

To make things worse, the quality of crude oil purchased by refineries statewide (and nationally) is degrading, as refineries switch to cheaper, higher-sulfur crude oil to increase already- record profits. More sulfur in the crude means more acutely hazardous materials in refineries, and increased energy use to remove the contamination from fuels. While refineries are allowed dirtier inputs, electric power plants are required by the state to clean up inputs. Although many new fossil-fuel power plants are still being unnecessarily permitted, the state is requiring phase-in of alternative energy for electric power plants (in California's Renewable Portfolio Standard requiring 33% renewables by 2020). But for refineries, the State is projecting **more refinery fossil fuel capacity** for the future.[2] Almost zero refinery emissions reductions are required in the State's greenhouse gas plan, despite hopes the plan would clean up refinery greenhouse gases and co-pollutants (smog-forming and toxics resulting from fossil fuel combustion).

Oil refineries are already major pollution sources, from fossil fuel evaporation and burning vast quantities of fossil fuel energy to make gasoline, diesel, and jet fuel. Oil refineries take crude oil, separate it into components, crack and reform it, and treat it to remove contamination (such as sulfur). Refineries are now building high-energy processing units to refine dirtier crude oil (more hydrogen plants, more cracking, coking, etc.). Refiners are currently expanding in a way that will lock us in to higher-pollution infrastructure for the decades to come. While these increases affect us all, the local impacts are concentrated most in communities of color. The population in Wilmington in Southern California is 85% Latino.

Wilmington/Carson not only includes about a third of the entire state's refining capacity, it has many other major pollution sources in or nearby, including the Ports of Los Angeles and Long Beach, the Alameda railway Corridor, many thousands of diesel truck trips per day, sewage treatment, recycling facilities, autobody shops, and heavy oil drilling in residential areas. New permitting policies are greatly needed to address bad decisions allowing unnecessary increases in fossil fuel pollution and Cumulative Impacts. This is especially so when unprecedented alternative energy options are available. Serious action to phase in clean energy alternatives must be taken.

Our report finds:

- California has a large oil refining capacity—over 2 million barrels per day (bpd) of crude oil refined in three regions. **The largest refining capacity in the state is in the Los Angeles region (about 1.25 million bpd of crude oil refining)**, followed by the San Francisco Bay Area with about 860,000 bpd refining capacity, with another 150,000 bpd in the Center of California). Even a single small refinery is a major air pollution source. (See maps on the following pages.)

- **Wilmington/Carson in the LA region has the highest concentration of refineries in the state (about one third the state's capacity).** About half Los Angeles' refining capacity is concentrated in the Wilmington/ Carson area (five refineries and about 650,000 bpd).

- Refineries are the largest stationary sources of smog precursors. In the Los Angeles region, refineries dominate the top **15 VOC (Volatile Organic Compound) emitters**, out of many hundreds of Stationary Sources listed by the South Coast Air Quality Management District (SCAQMD) in the 2007 Air Quality Management Plan. **The Wilmington Area emits about half the refinery VOCs emissions**[3] (about 1,600 out of 3,200 tons per year) in the LA region.

- **In addition to impacts from intensive oil refining, the Wilmington area is burdened by Cumulative Impacts from many other fossil fuel pollution sources,** including the Ports of Los Angeles and Long Beach, the Alameda railway Corridor, the I-110 and 710 freeways, sewage treatment, thousands of diesel truck trips/day, recycling facilities, auto body shops, and many other sources. Greatly expanded drilling of a large oil field in the middle of a Wilmington residential neighborhood also badly exacerbates Cumulative Impacts.

- **Refinery emissions of greenhouse gases in California are very large (about 40% of industrial emissions,** and almost 10% of the state's greenhouse gases), and getting much worse.

- Among many other impacts, **climate change will severely impact air quality due to higher temperatures causing more smog formation,** which is already at severe levels, especially in Southern California.

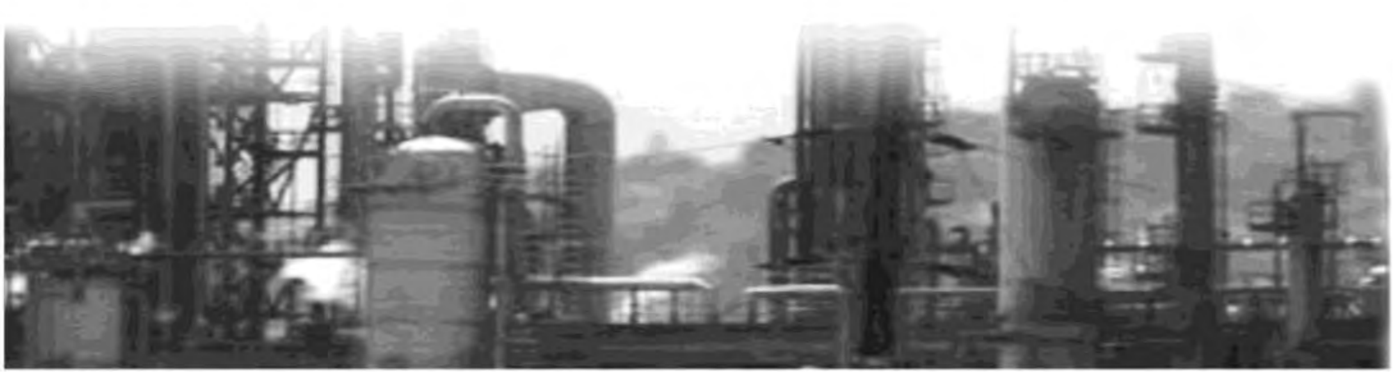
- Climate change also increases runaway wildfires.[4] Air quality severely degrades during wildfires, which can cause extreme levels of particulate matter and health impacts.

- **Oil Refinery Fossil Fuel Combustion emits many pollutants—the same flame emits local toxics, regional smog-forming pollutants, and global pollutants (greenhouse gases).** The solution for all these problems is the same: phasing out fossil fuels.

- Sulfur content in crude oil (a contaminant that turns into hazardous hydrogen sulfide and sulfur oxides during refining), is increasing. This potentially means increased emissions associated with asthma impacts. Processing dirtier crude oil also means much higher energy use. **While California power plants are required to switch to at least 20% renewable energy (with plans up to 33%), <u>oil refineries are switching to dirtier crude oil and expanding.</u>**

- **We have unprecedented opportunities to phaseout fossil fuels from refineries and other sources for good, due to real alternatives available in large quantities, instead of investing in expansions of dirtier crude oil and expanded refining.**

- **We should clean up refineries by requiring Best Available Control Technology standards for existing sources, and limits on dirty crude oil inputs.** Refineries can also switch from fossil fueled electricity to clean sources, and reduce refinery production. We are paying the price for fossil fuels, better spent on clean energy.



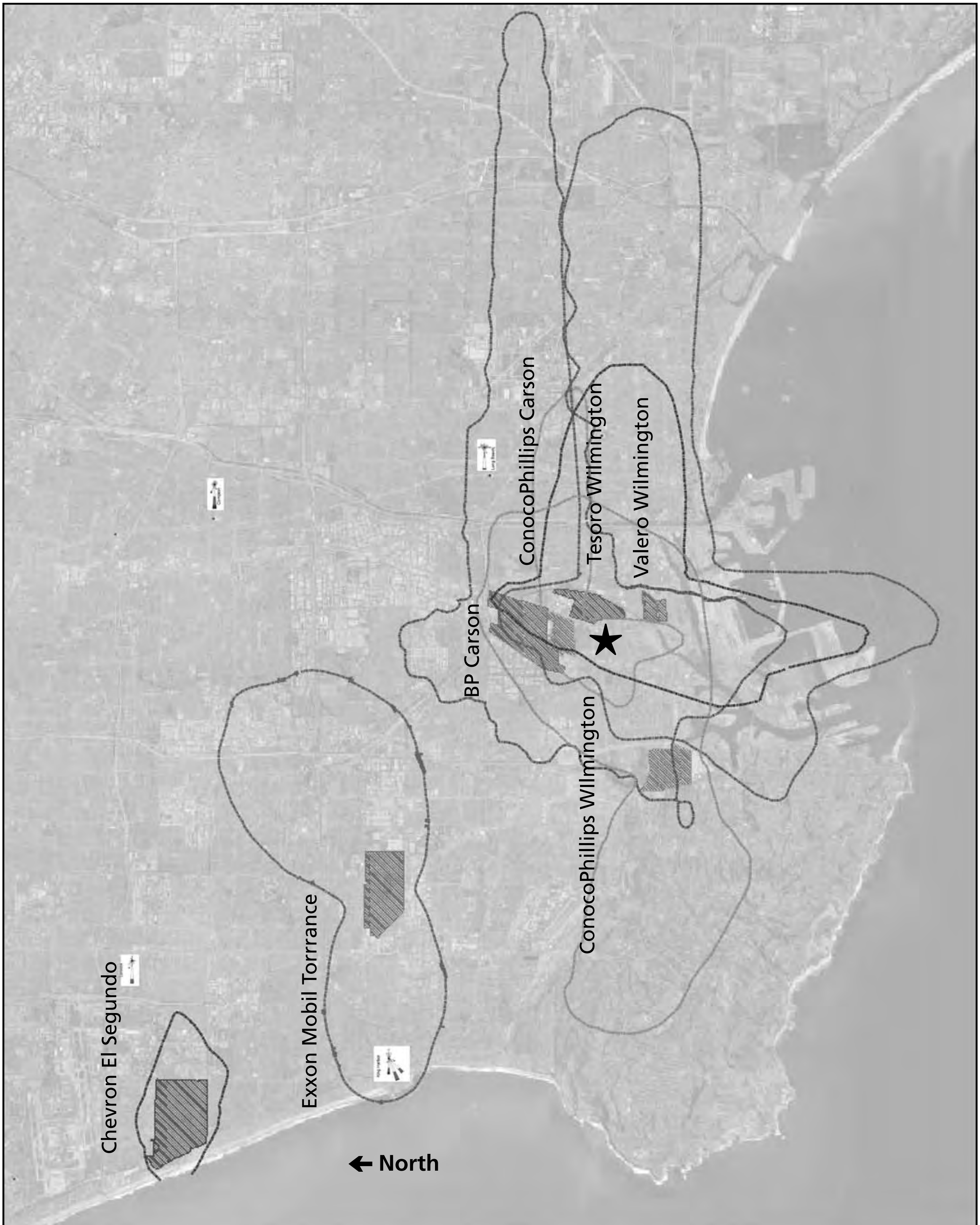
Although heavily-industrialized, Wilmington is residential, with many schools

Industry may be the defining characteristic of Wilmington, but it is also home to 53,000 residents, over 45,000 identifying as Latino. Wilmington is low income, with around 24% of families living below the national poverty level. The City represents a clear example of environmental injustice, where a community of color in a lower socio-economic bracket is disproportionately impacted by multiple polluting facilities. CBE has worked since the '90s in Wilmington to empower residents demanding a better quality of life, and has been successful in winning enforcement of regulations and tough new policies. However, Wilmington remains a highly-impacted hub of our fossil-fueled society.

In addition to Wilmington's large residential population, the City contains many schools:

- 6 Primary Schools (Grades 1-5): Island Avenue Elementary; Broad Avenue Elementary School; Fries Avenue Elementary School; Gulf Avenue Elementary School; Hawaiian Avenue Elementary School; and Wilmington Park Elementary School.
- 3 Secondary Schools (Grades 6-12): Wilmington Middle School; Phineas Banning High School; and Harbor Teacher Preparation Academy.
- 4 Private Schools: Holy Family Parish School; St. Peter & St. Paul; Wilmington Christian School; Pacific Harbor Christian School.
- 3 Continuation Schools: Banning-Marine Ave Adult Center; Harbor Occupational-Skill Center; Avalon High School.
- Two Colleges and Universities: Los Angeles Harbor College and National Polytechnic College of Engineering and Oceaneering.

Students at both Harbor Teacher Preparation Academy and Los Angeles Harbor College complain frequently about fumes emanating from ConocoPhilips. ConocoPhilips is less than a mile from both campuses. **Student athletes on the campuses reported refraining from practicing sports on days when air quality is especially bad.**



Wilmington, CA (LA Region)
Ground zero for largest number of overlapping refinery air pollution plumes in California

CUMULATIVE IMPACTS – Refinery air pollution plumes converge in Wilmington, CA

Cumulative Impacts — The health and environmental impacts of pollution from many different sources added together. *Wilmington is a prime example, with multiple refineries, freeways, ports, and many smaller pollution sources which can create pollution hotspots. Frequently, permitting decisions don't take into account these added impacts, but treat them separately. Communities of color are usually impacted the most. There is a grassroots movement to win good permitting policies to prevent Cumulative Impacts that hurt people's health. The map to the left shows Cumulative Impacts from the air pollution of many different oil refineries that add together in Wilmington/Carson.*

Mapping can easily show us things we can't directly see on the ground. For instance, the map at the left provided by the South Coast Air Quality Management District at a public workshop,[5] shows where air pollutants from refineries blow over the course of the year, as winds change.

Within the different colored outlines on the map are the areas receiving at least a certain baseline level of pollution from the local refinery, averaged over the year. Areas outside the outline can still receive refinery pollution, but receive lower levels than inside the outlines. Some areas inside receive even higher levels. The map only includes pollution from the refineries, and not from all the other pollution sources in the region.

The outlines are made by a computer model, and indicate areas within, with a cancer risk of greater than 1 in a million from each local refinery's emissions. Even though the Air District modeled cancer-causing pollutants, the model shows in general where wind blows other pollutants during the year (because these other pollutants emitted at the same time disperse in the same direction). To get these outlines, the computer starts by calculating air pollution concentration at different points on the map after the pollutants are released by the refinery, by taking into account the wind speed, direction, and weather conditions; then the computer recalculates the air pollution concentrations at each point again as conditions change daily. The final plumes come from averaging pollution concentration over the year. Of course, knowing how much pollution comes out is essential, and we know that this is frequently underestimated.

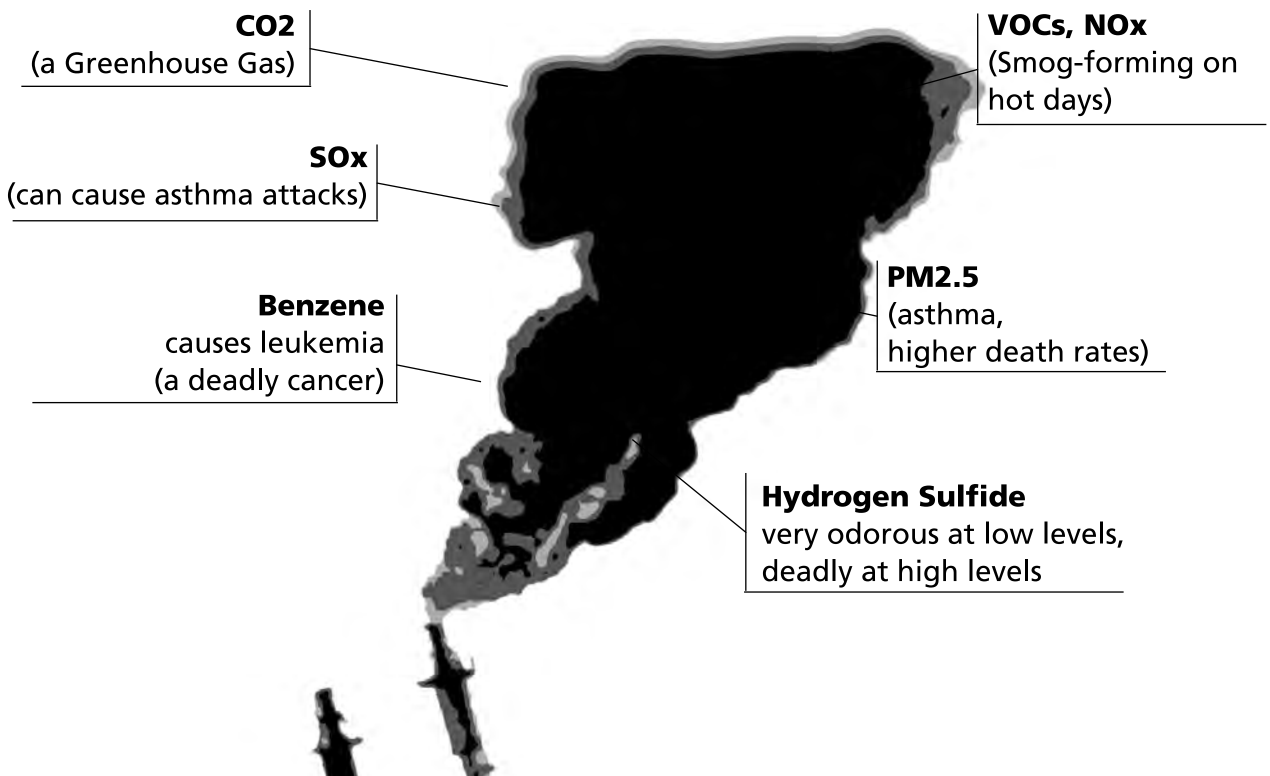
The results show that the Wilmington/Carson area has emissions from five different oil refineries plumes, adding together to create Cumulative Impacts from all five on a yearly average. No other area in the state has five refineries' emissions in one place over the year. Actual health impacts from these sources together is really not known.

The map only shows continuous emissions sources, not accidental releases that can occur in a short time. Of course, other areas outside the map's air pollution plumes are impacted as well, and even having one relatively "small" refinery nearby can cause major air pollution. Each refinery by itself can have a large impact (because oil refineries emit large volumes of gases that cause smog and emit toxic chemicals). But living next to or working in an area with multiple oil refineries (plus other pollution sources) results in Cumulative Impacts, not addressed directly by public policy protections.

The map at left shows that the Wilmington/Carson area of the LA air basin has the largest number of refinery plumes affecting any region in the state. CBE will be publishing a report on Cumulative Impacts in the region in the future including many other pollution sources.

What air pollutants come out of oil refineries?

Burning fossil fuels at oil refineries (and by cars, trucks, ports and oil drilling) emits local toxic air pollution, regional smog-forming pollutants, and global greenhouse gases, at the same time.



Phasing out fossil fuels will solve all of these pollution problems at once

We have ample opportunities for phasing out fossil fuels.

1. **Clean up oil refineries** through a limit on dirty crude oil inputs, require energy-efficiency at refineries by replacing old boilers, heaters, and other inefficient equipment require Best Available Control Technology to reduce all pollutants, require refineries to use clean alternative energy instead of grid electricity.
2. **Ramp up alternative energy** (Plug in hybrid vehicles can get 100 miles to the gallon, drastically reducing the need for refineries; wind energy and solar panel use is increasing dramatically but needs public policy support; many other alternatives are already available).
3. **Energy conservation gets the biggest pollution reductions.** (See end of report for more detail.)

Refineries are the largest stationary sources of smog

In the entire LA Region, which is made up of hundreds of stationary (non-mobile) air pollution sources, refineries dominate the top 15 Volatile Organic Compound (VOC) polluters.[6] Refineries make up about 73% of the top 15 polluters' emissions below. VOCs chemically react on hot days to form ground-level ozone, the main component of smog, causing asthma attacks and hurting normal adults' breathing. Many VOCs are toxic without chemically reacting in the air (such as benzene, which causes leukemia). In addition to directly emitting pollution, oil refineries produce fuels used in cars and trucks that cause even larger volumes of pollution.

The Wilmington/Carson Area by itself emits about half of the LA Region's total refinery emissions listed below (about 1,600 of 3,200 tons per year).

	Company	City	Tons per year of Volatile Organic Compounds
1	**CHEVRON**	**El Segundo**	**837**
2	**EXXON MOBIL**	**Torrance**	**676**
3	**TESORO (previously Shell)**	**WILMINGTON**	**506**
4	**BP**	**CARSON**	**429**
5	Laco Bathware	Anaheim	278
6	TABC, Inc.	Long Beach	278
7	**CONOCO PHILLIPS**	**WILMINGTON**	**238**
8	Dart Container Corporation of CA	Corona	195
9	**VALERO (prev. Ultramar)**	**WILMINGTON**	**174**
10	Kinder Morgan Liquids Terminals, LLC	Orange	172
11	Anheuser-Busch, Inc.	Van Nuys	164
12	Inland Paperboard and Packaging, Inc.	Ontario	150
13	**CONOCO PHILLIPS**	**CARSON**	**138**
14	TESORO	CARSON	128
15	**PARAMOUNT**	**Paramount**	**119**
		Total for Refineries above	**3,245 tons per year**
		Total all of above	**4,482 tpy**

Note: CBE believes refinery emissions are greatly underestimated (such as emissions from startup/ shutdown, emergencies, leaking gases, storage tanks, and many others), but the numbers above give a feel for relative ranking of refineries according to SCAQMD.

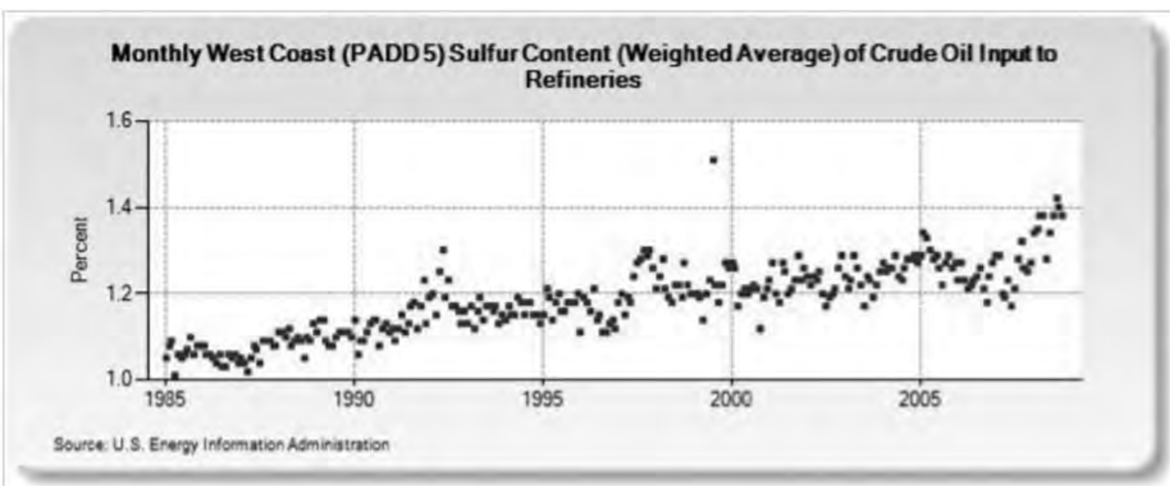
Refinery crude oil inputs are getting dirtier

Two hazardous Sulfur Compounds are present in refineries at increased levels because refineries are switching to higher-sulfur crude oil:

1. **Sulfur Dioxide (SO2)** can cause:
   - Breathing and eye irritation and asthma attacks
   - Respiratory illness and heart disease aggravation

2. **Hydrogen Sulfide (H2S)** can cause:
   - Eye, nose, and throat irritation at low levels; headache, dizziness, nausea, vomiting, cough, breathing difficulty at moderate levels
   - Shock, convulsions, coma, and death at high levels (H2S has killed many workers)

Crude Oil Sulfur Contamination in West Coast Refineries (inching up since 1985), increased more drastically in recent years.[7]



The US Energy Information Administration (EIA) also found this increase on a national basis:

> **"The average sulfur content of U.S. crude oil imports increased from 0.9 percent in 1985 to 1.4 percent in 2005 [26], and the slate of imports is expected to continue "souring" in coming years. Crude oils are also becoming heavier and more corrosive . . ."[8]**

> **California refineries dominate the data in the chart for the West Coast** region shown above called PADD5.[9] (California makes about 67% or 2.2 million barrels per day (bpd) in 2006 out of 3.2 million PADD5 total). EIA does not provide such data separately for California in total. Also, only imported crude data is provided by EIA for individual refineries, so domestic crude from California and Alaska are missing. See table on pages 14–15 for more on crude oils used by California refineries. PADD5 also includes Alaska, Washington, Hawaii, a tiny Nevada refinery,[10] and Arizona and Oregon (with no refineries). **EIA reported average October 2008 PADD5 sulfur at 1.38% (which is "sour" or high-sulfur crude oil).[11]**

Refinery greenhouse gases are also big and getting worse because of dirty crude

"Refineries are the largest energy using industry in California and the most energy intensive industry in the United States...After Texas and Louisiana, California has the largest petroleum refining industry in the country." (Lawrence Berkeley Labs[12]) The California Public Utilities Commission found that industrial facilities in California emit about 23% of California's total greenhouse gases, and refineries emit about 40% of industrial emissions.

Oil refineries directly emit about 10% of the state's total Greenhouse gases. Oil refineries also make transportation fuels, so they are responsible for the additional 40% of California's greenhouse gases emitted by transportation. Refineries are adding and expanding energy-intensive equipment in order to process higher-sulfur crude oil, including hydrogen plants and hydrotreaters (for stripping sulfur contamination), cracking and coking, for processing heavier crude oil, etc. This is drastically increasing Greenhouse Gas (GHG) emissions.

One new refinery hydrogen plant can emit over one million tons of CO2 every year, and many refineries are adding new hydrogen plants.[13] (Hydrogen is used by refineries to strip sulfur contamination from fuels, and for other fossil fuel processing. This is not to be confused with hydrogen used as an alternative energy source, because refineries use very large amounts of fossil fuels to make this hydrogen.)

CLIMATE CHANGE WILL SEVERELY DEGRADE OUR AIR

Photo: istockphoto.com/Daniel Stein

MORE SMOG—

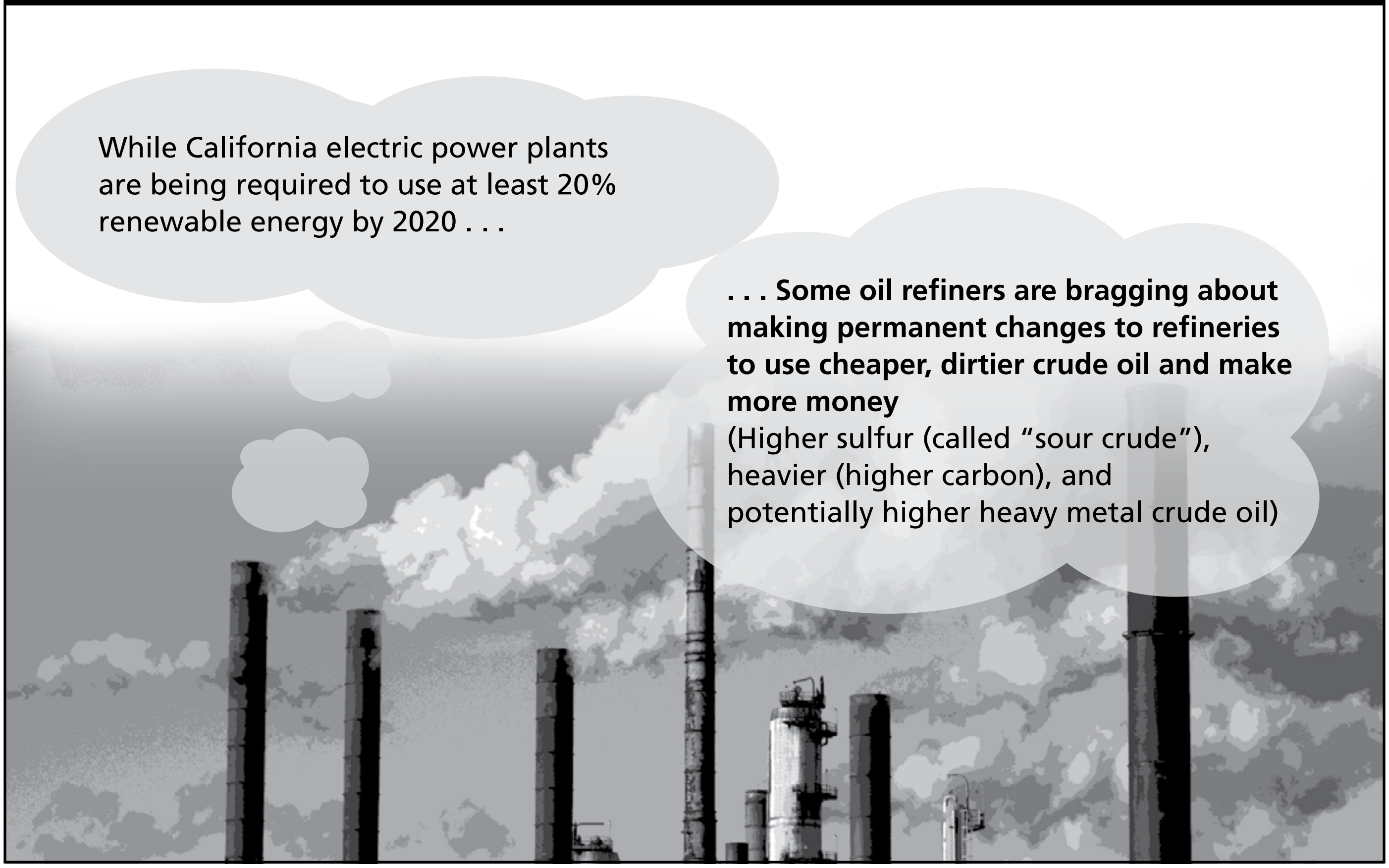
75% more "bad air" days due to higher temperatures from climate change in the Los Angeles region and other areas by the end of the century.[14]

Photo: Getty Images

MORE PARTICULATE MATTER FROM WILDFIRES—

Severe air quality occurred during the 2008 wildfires for many months through large regions of California, where thousands of fires raged out of control. This was the worst wildfire season ever. Many people suffered severe respiratory impacts. Frequency of runaway wildfires is projected to increase due to hotter, drier conditions.[15]

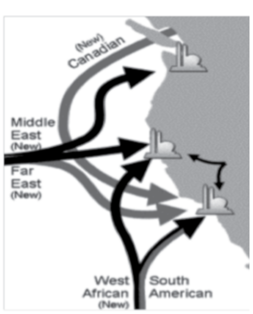
Instead of reducing fossil fuel use, oil refineries are expanding, using dirtier crude oil, & making record profits.



In the words of the oil industry:

"**Valero also spent heavily to upgrade many of those refineries to process lesser and cheaper grades of crude oil.** That reduces Valero's operating costs and widens its profit margins. **"We figured we would have the advantage of using a cheaper feedstock . . ."**[16]
(*LA Times*, 7/ 24/01 (emphasis added))

"**Valero's strategy of basing its feedstock largely on sour crude oil,** which was selling at a large discount to sweet crude oil. . . Valero then nearly tripled its profits one year later, making $1.8 billion on revenues of $54.62 billion."[17] *[Sour crude oil means high-sulfur contamination; sweet crude oil is low sulfur (which is less polluting).]*



"Tesoro will integrate with the supply of heavy, sour crudes for Golden Eagle which opens up new sources of economic supply for both refineries."

The Tesoro report to the SEC also includes this map, showing heaviest Canadian tar sands crude shipped to LA. (Report to Securities Exchange Commission)

OTHER TESORO REFINERIES[18]

"In 2002, we completed a heavy-oil conversion project, which allows the refinery to process a larger proportion of lower-cost heavy crude oils, while producing a larger proportion of higher-value products. A distillate treater also was installed allowing the refinery to increase production of low-sulfur diesel and jet fuels." (Anacortes Washington)

CHEVRON EL SEGUNDO CA

"The objectives of the proposed project at the El Segundo Refinery are to: . . **Allow the Refinery to efficiently and reliably process a wider range of crude oils, including higher sulfur-containing crude oils;"**[19] (Environmental Impact Report 2008 ("EIR"))

"Chevron is currently proposing modifications to the existing No. 4 Crude Unit and Delayed Coke Unit to enable the refinery to increase heavy crude oil refining capacity with the potential for minor increases in product production volume, " SCAQMD, http://www.aqmd.gov/CEQA/igr/2006/april/413-05.pdf

CHEVRON RICHMOND CA

Design and engineering for a project to increase the flexibility to process lower API-gravity crude oils at the company's Richmond, California, refinery continued in 2007.[20] Chevron 10K Report to the SEC (*Note: API gravity is a reverse scale; lower API means heavier crude oil.)*

CONOCOPHILLIPS RODEO CA

The Refinery would use heavy gas oil (HGO) that is produced at the Refinery, but is currently being sold into the heavy gas oil and fuel oil markets, to produce cleaner-burning gasoline and ultra-low-sulfur diesel (ULSD) fuels targeted for the California market. Overall, Refinery production following implementation of the Proposed Project would increase by up to approximately 1,000,000 gallons/day or 30 percent over current Refinery production levels. (Draft EIR[21])

OTHER U.S. CONOCOPHILLIPS REFINERIES

ConocoPhillips is spending $1.3 billion on its East Coast refineries and $1.8 billion in the Midwest and Rocky Mountain regions, Nokes said. . . . **The investments will increase the company's total high-sulfur crude processing to 41% from 28%. High-sulfur or "sour" crude is costlier to refine but is significantly cheaper than the U.S. benchmark light sweet crude. The upgrades will allow ConocoPhillips to refine more high-sulfur oil from Canada.** (*LA Times*[22]) *(Note that the Wilmington plant is already using high-sulfur.)*

California refineries: How big are they? How dirty is the crude oil to make gasoline, diesel & jet fuel?

The table below shows crude oil used by each California refinery, split into three big regions. Crude oil is processed through heating, cracking, and chemical reactions to make gasoline, diesel, jet fuel, etc. The first column shows the maximum capacity of the refinery to process crude oil (a volume in barrels per day or bpd), the next shows the volume of crude oil imported to each refinery from outside the US, and the last shows the domestic (US) crude oil used at the refinery. The US Energy Information Administration (EIA) provides public data online on imported crude oil, but not domestic crude. Domestic crude information had to be searched through various sources and was not always available. See notes at end of this report. The Wilmington/Carson area makes up almost a third of the state's total refining capacity.

(In order of largest to smallest in each region)	**MAXIMUM CRUDE OIL CAPACITY 2009 Barrels/day (bpd)**	**IMPORTED CRUDE USED 2006[23] Capacity (bpd) Average Sulfur % Density (API °)**	**DOMESTIC CRUDE USED 2006 estimated[24] (bpd)** ***Less data available — On average— about 80% sour[25]**
LOS ANGELES REGION 1,250,500 bpd, WILMINGTON/CARSON total: 649,000 bpd			
BP **Carson**	**275,000**	134,000 bpd – 51% Sulfur: 1.38% **SOUR** 29.88° Intermediate.	91,980*
CONOCOPHILLIPS **Wilmington & Carson** *(two integrated sites)*	**139,000**	68,452 bpd – 49.2% Sulfur: 2.89% **SOUR** 30.44° Intermediate	51,500*
VALERO **Wilmington** *(previously Ultramar)*	**135,000**	61,742 bpd Sulfur: 1.55% **SOUR** 22.35° Heavy	13,976 **SOUR** Heavy
TESORO **Wilmington** *(previously Shell)*	**100,000** Sulfur: 2.7%[26] **SOUR** 21.9°[27] Heavy	23,645 bpd – 24%	54,644 San Joaquin pipeline & LA basin (SEC)
CHEVRON El Segundo	**270,000**	245,097 bpd – 94.3% Sulfur: 1.61% – **SOUR** 27.79° Intermediate	10,879*
EXXON MOBIL Torrance	**149,000**	0	109,135*
PARAMOUNT Paramount	**53,000**	0	36,500*
EDGINGTON Long Beach	**35,000**	5,903 bpd - 22.7% Sulfur: 1.55% – **SOUR** 23.50° Heavy	14,671*
LUNDAY THAGARD South Gate	8,500	0	6,205*

Continued from previous page)	MAX CRUDE OIL CAPACITY	IMPORTED CRUDE USED	DOMESTIC CRUDE USED
BAY AREA 861,000 bpd			
CHEVRON Richmond	**240,000**	145,323 bpd – 59.8% Sulfur: 1.26% **SOUR** 34.04° Interm / Light	71,232*
VALERO Benicia	**170,000**	33,871 bpd – 23.5% Sulfur: 0.42% – Sweet 20.71° Heavy	80,394 **SOUR**
TESORO Avon / Martinez	**166,000**	58,710 bpd – 35.4% Sulfur: 0.73% Moderate 29.45° Intermediate	78,322*
SHELL Martinez	**165,000**	26,806 (17.3% Sulfur: 2 .09% **SOUR** 21.08° Heavy	93,581*
CONOCOPHILLIPS Rodeo	**120,000**	21,839 bpd – 28.7% Sufur: 0.26% Sweet 35.80° Interm/ Light	39,538*
OTHER CALIFORNIA REFINERIES about 150,000 bpd			
BIG WEST (Flying J) Bakersfield	**70,000**	0	48,180*
KERN OIL Bakersfield	**26,000**	0	18,980*
CONOCOPHILLIPS Santa Maria	**41,800**	not available	32,266 *
GREKA Santa Maria	**9,500**	not available	not available
TENBY Oxnard	**2,800**	0	2,044*

- VOLUME OF CRUDE OIL processed in the refinery is in barrels per day (1 barrel = 42 gallons)
- SOUR CRUDE = HIGH SULFUR — greater than 1% sulfur contamination (though definitions vary)
- SOUR CRUDE CREATES MORE HAZARDOUS SULFUR GASES DURING REFINING
- SWEET CRUDE = LOW SULFUR
- API GRAVITY is a measure of how heavy (or dense) the crude oil is. This is a reverse scale so that lower API numbers mean heavier crude oil. Heavy crude takes more energy to process, and more pollution is generated. Heavy or "high carbon" crude is frequently high sulfur, with higher heavy metals.

Environmental racism: Cumulative impacts of fossil fuels in Wilmington go well beyond refineries

Although this report focuses on the oil industry, it is important to note Wilmington's severe Cumulative Impact burden by identifying the many other major pollution sources in or very nearby Wilmington. There is a need for effective Cumulative Impact policies by government agencies involved in planning and permitting, to reverse these impacts. CBE will be publishing a fuller report on Cumulative Impacts in the region in the future.

Environmental injustice or environmental racism is a well-documented and severe problem across the country, where communities of color and low-income communities bear a higher concentration of pollution compared to white communities. Unfortunately, Wilmington is a prime example. Although having five oil refineries puts Wilmington into a class by itself due to that fact alone, the pollution burden does not stop there.

Pollution sources in or near Wilmington add up!

Five Oil Refineries	**Oil Drilling**
Ports of LA & Long Beach	**Alameda Corridor (railway)**
I-110 & 710 Freeways	**Diesel Trucking**
Auto Body Shops	**Recycling Facilities**
Sewage Treatment (& much more)	**Regional Smog**

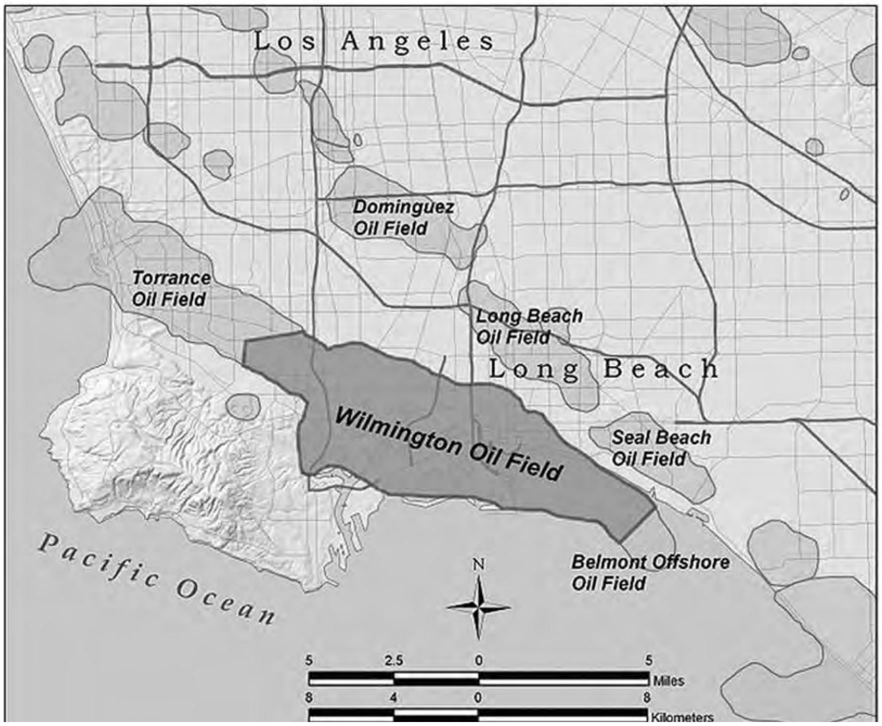
Communities of color & the low income in Wilmington bear the cumulative impact burden of fossil fuel.[28]

	Wilmington	LA
Hispanic or Latino of any race	85%	45%
Median household income	$30,260	$42,190
Individuals below the poverty level	27%	18%

Wilmington:
Refineries, Ports, Oil Drilling, Railways, Freeways, Diesel Trucking & more

- Cumulative Impacts means communities receive pollution from many different sources together
- New policies requiring stricter permits are greatly needed!

In addition to oil refining, oil drilling is causing more fossil fuel cumulative impacts right in Wilmington



As if ports, freeways, and refineries weren't enough, **Wilmington contains the third largest oil field in the U.S.**

The oil field was previously considered depleted, but in recent years with new methods and the incentive of high oil prices, drilling has ramped up. CBE's Wilmington oil drilling campaign began in 2006. **People living around the Warren E&P drilling operations contacted CBE to report severe noise, sickening smells, air and water pollution, and breathing problems after the company purchased the site.** Neighbors reported constant diesel truck traffic through the residential streets, dust and oily residue covering and invading homes, constant flaring (from a stack burning oil field gas), and heavy vibrations at all hours of the day and night, seven days a week.

Although drilling operations occurred at this site in the past (at a much reduced level), when Warren E&P purchased the facility, production drastically increased, as did impacts on the community where it sits. Recent technological advances now allow oil companies to drill laterally, reaching out underground to large areas, that previously would have been drilled from other locations. That means much larger volumes of oil and gas can come out of one drilling site, in a very intensive operation. Warren E&P has concentrated its drilling operations in this way at the "Wilmington Town Lot," in a residential neighborhood. Even though it borders an industrial area, it is hard to understand why such a neighborhood site would be chosen.

After neighbors called us, CBE worked together with the community to devise strategies to stop the impacts of the drilling. These included evaluating Warren's compliance with air, water, toxics and land use regulations, identifying methods and equipment to reduce flaring and air pollution, pushing for enforcement of existing bans for large diesel truck traffic through the neighborhood, getting paving and street-sweeping requirements implemented to stop the heavy construction dust blowing offsite, and pushing for better government agency monitoring.

CBE contacted the South Coast Air Quality Management District and the City of Los Angeles, and together with community members met with government officials and the company. CBE community organizers and Warren neighbors developed logs of impacts, took photos, videotaped flaring, and evaluated noise levels. Meanwhile CBE lawyers and scientists researched and documented health and environmental impacts, legal requirements, and Warren's permit limits.

It became clear that Warren was not in compliance with permit conditions and limits. After we contacted the Air Quality Management District, the regional agency issued a Notice of Violation to Warren for burning gases in the flare, far above its permit limits. Unfortunately the Air District then began rushing through a permit that would have allowed even more flaring. CBE challenged it and the Air District withdrew it. CBE and neighbors met with the Air District staff and chief to describe the severe conditions. The Air District began to develop a new compliance plan to reduce Warren's air pollution.

(continued next page)

Photo from video by Rember Sosa, neighbor to Warren oil drilling

In a CBE survey, Wilmington neighbors described oil drilling operations as "a living hell."

CBE organizers carried out a survey of neighbors after bitter complaints about Warren drilling, with the following different responses from neighbors:

- It's been different since the Warren site came to the neighborhood
- A lot of allergies, breathing problem, headaches, chronic problems, lack of sleep
- Get a weird taste in my mouth, difficulty in bad traffic, breathing, there's a breeze of dust, the house is full of dust, must close the windows in the house 24/7
- Mainly health problems—sleeping. House always has dust and oily residue, vibrations. I know my blood pressure is just on edge, I just have to leave. This can't go on much longer.
- Smell, noise, illness. Extreme breathing difficulties, Dr. visits
- Evening noise—more dust, smells, extensive lung illness, constant coughing—less sleep
- Lots of dust. Every morning lots of black film all over the cars
- Problems breathing. More dust in my home, headache
- Affected my health by asthma, community is dirt
- Headache, nausea, and difficulty breathing

Neighbors attend public meeting on Warren Oil Drilling Operations at Los Angeles Councilwoman Hahn's office

After the Notice of Violation, CBE and members intensified work on the land use front. As a result of communications with the City and Wilmington's representative Janice Hahn, the Zoning Administrator instituted a review of Warren's Land Use requirements. CBE and members documented the suite of impacts, and submitted legal and technical briefs.

The morning of the hearing, Warren packed the auditorium by providing free breakfast to busloads of Warren E&P shareholders and royalty recipients from outside the community who didn't have knowledge of local impacts. CBE members from the neighborhood were dismayed and offended by this show, but many still overcame their disillusionment and spoke out eloquently at the hearing. It took months before the Zoning Administrator issued a decision, adding few requirements including restrictions on hours of operation and trucking, but not sufficient to meet neighbors' concerns.

CBE and members continued documenting ongoing impacts from Warren, and pursued the Air District process, where the agency and polluter were collaborating on a long-term plan to relieve Warren of liability for its air violations. CBE testified and offered evidence at the quasi-trial conducted by the Air District Hearing Board on Warren's permit violations.

Neighbors urged the Board to reject the plan and require compliance with the law. Although the Hearing Board denied our challenge, the community efforts resulted in the Air District issuing a more protective compliance plan to decrease Warren's flaring, improve equipment, ultimately send gases offsite for sale instead of burning onsite, and more. Warren is now required to comply with more enforceable air protections.

Although CBE and neighbors were very dissatisfied with the formal decisions at the hearings, the community pressure meant that much was accomplished behind the scenes to get the City and the Air District to force Warren to clean up operations, while they awaited permit decisions. While neighbors are very happy that conditions have greatly improved, many are concerned that this may be only a temporary improvement.

HEALTH IMPACTS OF OIL DRILLING

- H2S and other hazardous sulfur compounds such as SOx (Sulfur Oxides) can hurt breathing, and can be released by oil drilling operations including well heads, pumps, piping, separation devices, storage tanks, and flaring.
- The US Agency for Toxic Substances and Disease Registry found: People can smell H2S at low levels. Lower level, long-term exposure can cause eye irritation, headache, fatigue, respiratory irritation, and at high levels, death.[29]
- Studies found people living near oil and gas wells had higher levels of many diseases.[30]
- Oil drilling operations also cause emissions of VOCs (Volatile Organic Compounds), which include smog-producing and cancer-causing chemicals.

People are concerned that Warren may only be temporarily on its best behavior, prior to the next permit approval needed, and may relapse in the future. The facility is slated to further increase production for years. There is also a major concern that reduced noise and pollution is due to reduced production because crude oil prices are currently down again. Warren may have ramped down production until prices go up again. If production increases greatly, there is concern impacts could increase greatly.

Neighbors are also very frustrated about foundation damage to their homes that was never compensated. Continued watchdogging is needed to protect neighbors from this terribly inappropriate siting. **A serious Cumulative Impact policy could have prevented this bad siting.**

A FEW CAMPAIGN RESULTS

	Positive Result for Now?	Permanent Solution?
Diesel trucking through neighborhood	✔	?
Construction dust from dirt	✔	✔
Continuous flaring	✔	?
Noise	✔	?
Smells	✔	?
Foundation damage	☹	☹

- The frequent, illegal diesel trucking through the neighborhood has stopped; the crude oil is now piped offsite instead of trucked.
- Extreme construction dust is apparently permanently stopped on the main site. Warren has now complied with its original requirement to pave the site (though a nearby area is still in question)
- Constant flaring has stopped for now
- Noise has improve greatly, possibly temporary
- Smells have improved

RECOMMENDATION 1 — CLEAN UP REFINERIES, REDUCE PRODUCTION

A. SET A CAP ON DIRTY CRUDE OIL & STOP EXPANDING REFINERIES

- Set standards for refinery inputs requiring limits on use of heavy, high sulfur crude oil (just like electric power plants which are switching to lower carbon fuels)

B. REQUIRE ENERGY EFFICIENCY & BEST AVAILABLE CONTROL TECHNOLOGY TO REDUCE ALL POLLUTANTS

- **Refineries need energy audits to identify the worst energy users at each refinery.** The worst energy users emit not only greenhouse gases, but smog forming chemicals and toxics from combustion of fossil fuels, so reducing energy use cleans up most or all pollutants. The biggest growing energy users at refineries include: Hydrogen Plants, Hydrotreaters, Hydrocrackers, Fluid Catalytic Crackers, Cokers, Sulfur Recovery Units, Boilers & Heaters (many which were built as long ago as the 1930's).
- **BACT is a well-tested Clean Air Act method of cleaning up industrial polluters.** New sources are required to meet the pollution control levels met by the best controls in use in the nation. It's time we applied BACT (or BARCT — Best Available Retrofit Control Technology) to existing refinery sources (not just new sources).
- **Remove Methane Exemptions in smog regulations for refineries and all sources.** Methane was previously considered not to cause smog formation, and is exempted from emission limits, but Harvard and Princeton studies show that methane is not only a potent greenhouse gas, but a smog precursor.[31]
- **No dumping and burning of "waste" gases through flares and Pressure Relief Devices:** Require sufficient gas recovery to recycle gases in refineries instead of burning in flares, and require Flare Minimization Plans for all flares. The Shell Martinez CA Refinery has achieved a very low level of flaring, including emergencies. Ban venting of Pressure Relief Devices to atmosphere, recycling gases in the refinery.

C. SWITCH REFINERY USE OF GRID ELECTRICITY TO CLEAN ENERGY

Refineries are current large users of fossil fuel grid electricity & should be required to switch to clean alternative energy electricity, frequently buildable on refinery land.

D. SET A GOAL FOR REDUCTION PRODUCTION & DEMAND

Like requirements for electric power plants renewable

We have unprecedented opportunities to clean up fossil fuels, eliminate their health and environmental impacts for good, & create green jobs!

RECOMMENDATION 2 — RAMP UP AVAILABLE ALTERNATIVES

A. CONSERVATION IS BY FAR THE BIGGEST OPPORTUNITY FOR REDUCTION FOSSIL FUEL USE, for example:

If we had Vehicle Fuel Economy standards we could save over 3 California's worth of gasoline:

If the U.S. increased mpg standards 45% higher using cost-efficient techniques, we'd save over 50 billion gallons of gasoline per year (Natl. Academy of Sciences), or over three Californias worth of gas. (California used about 15 billion gals/yr in 2003). Increasing fuel efficiency of cars & trucks by 3 mpg can save about 1 million barrels of oil/day or 5 times the amount the Arctic refuge might produce.

B. MANY CLEAN ALTERNATIVES ARE AVAILABLE

Plug-in Hybrid Electric Vehicles already achieve 60-100 mpg. Non-plug in hybrids are being converted to hybrids, achieving 60-100 mpg, and even 200 mpg under ideal conditions.[32] Running a plug-in would reduce average fuel cost by about half. Plug-ins also help wind energy by providing storage in the car batteries.

Photovoltaics (Solar Panels) could provide about 10% of the grid's electricity by 2030 without grid management problems (equivalent to 275 GW in the US) (*American Solar Energy Society*). PV installation is a fast-growing green jobs provider.

Concentrated Solar Power can economically deploy 80 gigawatts by 2030 in the US Southwest (equivalent to about 160 large fossil fuel plants at 500 megawatts each).

Wind capacity in the US is assessed at 245 gigawatts and higher with storage; over 10,000 megawatts are already in use. Wind power's low cost is expected to cause continued market penetration; the U.S. has large numbers of high quality wind sites. Best resources are Rocky Mountain and Great Plains states; also Sierras and Appalachians.

Most of the information above is from an excellent report on alternative energy, *Tackling Climate Change* from the American Solar Energy Society. See endnotes. [33]

These opportunities are unprecedented because of the ground-swell of installations of available alternatives, demonstrating that they work.

Glossary

Climate Change – a long-term significant change in patterns of average weather of the Earth. Thousands of scientists around the world have concurred that air pollution from human activities is causing climate change. Greenhouse gases, such as Carbon Dioxide (CO2) emitted when fossil fuels are burned in cars and by industry, as well as methane emissions from agriculture and industry, and other air pollutants in lesser quantities from various sources, trap the sun's heat in our atmosphere. In the past, more of this heat was reflected back to space, but now it is increasing temperatures on earth. CO2 is also naturally occurring in our atmosphere, but human use of fossil fuels for energy has caused a sharp increase IN CO2. Examples of impacts of climate change include melting of polar ice caps, mountain glaciers and snowpack, due to increasing average temperatures (projected to cause 1 billion people to lose their drinking water), extreme weather conditions including droughts and floods, tropical diseases moving northward, sea level rise (which is destroying certain island nations and threatens millions in coastal areas), more wildfires, increased intensity of hurricanes, increased smog due to hotter temperatures, extinction of many plant and animal species, and many other extreme impacts. Extensive documentation of climate change and impacts is available from numerous sources, including the Intergovernmental Panel on Climate Change (IPCC), at http://www.ipcc.ch/ipccreports/ar4-syr.htm .

Crude oil – a fossil fuel. Crude oil is made up of a mix of hydrocarbons (such as pentane, octane, benzene, methane, and many others). Crude oil is processed by separating, cracking, reforming molecules, and stripping contamination at oil refineries to make diesel, gasoline, jet fuel, kerosene, lube oil, heating oil, sulfur, and petrochemicals. Different crude oils originate from many parts of the world and vary in how heavy they are, and how much contamination is present (such as sulfur, heavy metals, and selenium).

Fossil fuels – Fossil fuels were formed from decayed prehistoric plants and animals over millions of years (hence the name fossil fuels). These include crude oil, coal, natural gas, other gases, fuels made from crude oil, such as gasoline, diesel, jet fuel, and others. Fossil fuels are hydrocarbon molecules, made up of different numbers of hydrogen and carbon. Using and burning fossil fuels causes emissions of greenhouse gases that cause global impacts, including carbon dioxide (CO2) and methane, but they also emit chemicals that cause local impacts such as smog-forming chemicals and toxics (such as benzene). Many people are working toward promoting available alternative energy in order to phase out fossil fuels and eliminate their associated severe respiratory (such as asthma), and other health impacts and global impacts.

Greenhouse gases – CO2 is the main greenhouse gas emitted, due to burning fossil fuels. Methane is another greenhouse gas, emitted by using fossil fuels, but also emitted by cows in agriculture, landfills, and other sources. Methane is much more potent than CO2 as a greenhouse gas, but is emitted in lower quantities. These two greenhouse gases are both emitted by oil refineries. Other greenhouse gases include nitrous oxide, sulfur hexafluoride, trifluoromethane, difluoroethane, carbon tetrafluoride, and others.

Renewable energy – Renewable energy is generated from natural resources — sunlight, wind, geothermal, tides – as opposed to fossil fuel, which is not renewable because it was formed over millions of years. See page 23 for a few important examples, plus a reference to a report with extensive information on alternative energy availability in the U.S.

Sweet crude oil / Sour crude oil – Sweet crude oil means lower sulfur crude oil – generally less than 1% sulfur contamination (though definitions vary). Sour crude oil is generally greater than 1% sulfur. Sour crude is cheaper than sweet crude, so if refineries invest in the equipment needed to process sour crude, they increase profits greatly. Unfortunately sour crude takes much more energy to process, which means that more fossil fuels are needed to make the gasoline and diesel from the crude. Thus more air pollution is generated. It also means a large increase in acutely hazardous sulfur compounds present at oil refineries, which can be emitted continuously, or during accidents.

Sulfur, Sulfur Dioxide (SOx), and Hydrogen Sulfide (H2S) and other sulfur compounds – Sulfur is solid, pale yellow nonmetallic element occurring widely in nature, but also present as a contaminant in different compounds found within crude oil. Sulfur by itself is a solid that is not harmful, but at oil refineries it is present as part of acutely hazardous sulfur gases including hydrogen sulfide, sulfur dioxide, carbon disulfide, and many other severely odorous and hazardous gases.

CO2 – or Carbon Dioxide – see greenhouse gases above.

Ozone – Ground-level ozone (or O3) is the main pollutant in smog, which causes respiratory harm and asthma attacks. Ground-level ozone is formed by the chemical reaction in the atmosphere of hydrocarbons and nitrogen oxides which are released during the burning of fossil fuels. Ozone on the other hand is naturally occurring in the upper atmosphere of the earth, where it shields us from harmful ultra-violet rays, and where it is called the ozone layer. Destruction of the ozone layer caused by chemicals emitted by human activities is a different problem from climate change caused by fossil fuel combustion.

PM 2.5 – Particulate matter of 2.5 microns or less (extremely small particles that can be inhaled deep into our lungs). Numerous studies have found that when PM2.5 increases, hospital death rates increase. It also causes respiratory irritation to normal adults. PM2.5 is emitted by the combustion of fossil fuels, and other sources.

VOCs – Volatile Organic Compounds are generally hydrocarbon gases. Different hydrocarbons have varying numbers of hydrogen and carbon atoms. One hydrocarbon (methane) is a strong greenhouse gas, but less toxic. Another hydrocarbon, benzene, is not a greenhouse gas, but is much more toxic, and is known to cause leukemia (a deadly cancer). Hydrocarbons in general react in the atmosphere to cause ground-level ozone, the main component of smog.

PRDs – Pressure Relief Devices at oil refineries, necessary to ensure that when pressure gets too high, the valve opens to keep equipment from blowing up. Unfortunately, many PRDs at refineries vent to the atmosphere, causing large bursts of harmful air pollution, including H2S, smog precursors, and greenhouse gases. PRDs can instead be vented to gas recovery systems.

SCAQMD – South Coast Air Quality Management District, which is responsible for cleaning up smog and issuing permits for equipment that can emit air pollution in the Los Angeles region. The SCAQMD implements many aspects of the Clean Air Act and state and local regulations. Community members can take part in public processes at the SCAQMD in order to win clean up of air pollution problems.

Stationary, mobile, and area sources of air pollution – A stationary source of air pollution is a single source that is not mobile. This includes both large and small sources such as oil refineries, power plants, other industries, and also dry cleaners, autobody shops, and many others. Non-stationary sources of air pollution include mobile sources (cars, trucks, trains, planes) and area sources (spray cans, consumer products, lawn mowers, that are small sources that add up over a large area).

More solutions – other CBE publications

Contact CBE for technical and legal publications identifying specific refinery pollution sources, and methods for minimizing and phasing out their fossil fuel pollution. A few key documents are listed below (soon to come on our website, at www.cbecal.org):

May 2008 Comments to the California Air Resources Board on the AB32 Scoping Plan

December 2008 Comments to the California Air Resources Board on the AB32 Scoping Plan with Addendum on Dirty Crude and Hydrogen use

Comments on the Chevron Richmond "Energy and Hydrogen Renewal Project"

Comments on the ConocoPhillips Rodeo "Clean Fuels Expansion"

Notes on Table – Sources of Crude, Sulfur, Content, API Gravity

Crude Capacity

BP http://www.bp.com/sectiongenericarticle.do?categoryId=9005027&contentId=7009099

Chevron El Segundo http://www.chevron.com/products/sitelets/elsegundo/about/

Exxon Mobil Torrance http://www.eia.doe.gov/neic/rankings/refineries.htm

ConocoPhillips Wilmington & Carson http://www.conocophillips.com/about/worldwide_ops/country/north_america/west.htm

Valero Wilmington http://www.valero.com/AboutUs/Refineries/Wilmington.htm

Tesoro Wilmington http://www.tsocorp.com/tsocorp/ProductsandServices/Refining/LosAngelesCaliforniaRefinery/LosAngelesCalifornia

Paramount Petroleum, Paramount http://www.eia.doe.gov/neic/rankings/refineries.htm

Edgington Oil http://www.eia.doe.gov/neic/rankings/refineries.htm

Lunday Thagard http://www.eia.doe.gov/neic/rankings/refineries.htm

Chevron Richmond http://www.chevron.com/products/sitelets/richmond/about/

Valero Benicia http://www.valero.com/AboutUs/Refineries/Benicia.htm

Tesoro Avon/Martinez http://www.tsocorp.com/TSOCorp/ProductsandServices/Refining/MartinezCaliforniaRefinery/MartinezCaliforniaRefinery

Shell Martinez http://www.piersystem.com/external/index.cfm?cid=159&fuseaction=EXTERNAL.docview&documentID=52481

ConocoPhillips Rodeo http://www.conocophillips.com/about/worldwide_ops/country/north_america/west.htm

Big West Bakersfield http://www.bigwestca.com/bigwest/appmanager/bwoc/home?_nfpb=true&_pageLabel=flyingjPortal_portal_page_18

Kern Oil Bakersfield http://www.kernoil.com/

ConocoPhillips Santa Maria http://www.greatvalley.org/sjpartnership/docs/101707/oil%20refineries_10-17-07.pdf

Greka Santa Maria http://www.eia.doe.gov/neic/rankings/refineries.htm

Tenby Oxnard http://www.eia.doe.gov/neic/rankings/refineries.htm

Valero Domestic Crude Supply

Valero Energy Corp (New York Stock Exchange)

Valero's Benicia Refinery is located northeast of San Francisco on the Carquinez Straits of San Francisco Bay. It **processe**s sour crude oils into premium products, primarily CARBOB gasoline. (CARBOB is a reformulated gasoline mixture that meets the specifications of the California Air Resources Board when blended with ethanol.)

Its Wilmington Refinery is located near Los Angeles, California. The refinery processes a blend of heavy and high-sulfur crude oils. The refinery can produce all of its gasoline as CARBOB gasoline and produces both ultra-low-sulfur diesel and CARB diesel. The refinery is connected by pipeline to marine terminals and associated dock facilities that can move and store crude oil and other feedstocks. Refined products are distributed via the Kinder Morgan pipeline system and various third-party terminals in southern California, Nevada, and Arizona. (Reuters, http://www.reuters.com/finance/stocks/companyProfile?symbol=VLO.N , Jan. 27, 2009)

Endnotes

1. Original graphics from: http://www.energy.ca.gov/maps/refinery_locations.html , graphics modified, labels added, data on barrels per day added by CBE

2. California Air Resources Board, Climate Change Proposed Scoping Plan Appendices (later finalized), Volume I: Supporting Documents and Measure Detail page C-155 states: "It is unlikely that refinery production will decrease in California over the next 12 years because of GHG reduction requirements. Due to the State's proximity to existing infrastructure (seaports, pipelines, etc.) and the developing Low Carbon Fuel Standard (LCFS)—which will hold both in-state and out-of-state producers to the same low carbon fuel standard—the demand for fuel products from California's refineries will not significantly change in the short term." http://www.arb.ca.gov/cc/scopingplan/document/appendix1.pdf

3. Draft 2007 AQMP Appendix III, Base and Future Year Emissions Inventories, 10/06

4. Presentation, Local Impacts of Global Warming, June 15, 2006, Dr. Margaret Torn, Climate Change and Carbon Management Program Head, Lawrence Berkeley National Laboratory, Earth Sciences Division: "Wildfire Severity Increases in California: -Fires burn hotter and spread faster, -More fires escape initial suppression efforts, - The number of potentially catastrophic fires doubles!"

5. SCAQMD, "Aerial photo with Aerial Photo with one-in-a-million risk isopleths of refineries," http://www.aqmd.gov/prdas/refinery/ref_agen_2005-08-18.html

6. Proposed Modifications to the Draft 2007 AQMP Appendix III, Base and Future Year Emissions Inventories, 10/06, Table D, 175th page (unnumbered), February 2007

7. http://tonto.eia.doe.gov/dnav/pet/hist/mcrs1p52m.htm, PADD5 also includes Alaska (373,500 bpd 2006), Washington State (673,850 bpd), and Hawaii (147,500 bpd). Alaska refineries included: North Pole Koch Industries, Inc, Kenai Tesoro Petroleum Corp, Valdez Petro Star Inc, North Pole Petro Star Inc, Kuparuk ConocoPhillips, Prudhoe Bay BP Exploration Alaska Inc; Washington State included: Anacortes Tesoro West Coast, Cherry PT BP W Coast Prodts LLC, Ferndale ConocoPhillips Co, Puget Sound Shell Oil Prdodts US, Tacoma U S Oil & Refg CO, Hawaii included: EWA Beach Tesoro Hawaii Corp, Honolulu Chevron USA Inc. (The Form EIA-810, "Monthly Refinery Report," is used to collect data on refinery input and capacity, sulfur content and API gravity of crude oil)

8. U.S. Energy Information Administration, Changing Trends in the Refining Industry, 2006, http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2006analysispapers/tri.html

9. Petroleum Administration For Defense Districts (PADD) - Five geographic areas into which the United States was divided by the Petroleum Administration for Defense for purposes of administration during federal price controls or oil allocation. OPIS, Oil Price Information Service, http://www.opisnet.com/market/glossary.asp#P

10. Nevada: Eagle Springs Refinery (Foreland Refining), 1,700 bbl/d (270 m^3/d), http://en.wikipedia.org/wiki/List_of_oil_refineries#Nevada, Oregon Department of Energy – Conservation Division: "There are no primary oil refineries in Oregon." http://www.oregon.gov/ENERGY/CONS/Industry/petro.shtml, EIA: Arizona has no refineries and receives its petroleum product supply via two pipelines, one from southern California and the other from El Paso, Texas. http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=AZ

11. http://tonto.eia.doe.gov/dnav/pet/pet_pnp_crq_dcu_r50_m.htm

12. Profile of the Petroleum Refining Industry in California, California Industries of the Future Program,The Lawrence Berkeley National Laboratory, LBNL-55450, Ernst Worrell and Christina Galitsky, Environmental, Energy Technologies Division,March 2004, page iii.http://ies.lbl.gov/iespubs/55450.pdf

13. ConocoPhillips Rodeo Refinery Clean Fuels Expansion Project, Contra Costa County Community Development Department, April 2007, Final Environmental Impact Report, page 2-6, http://www.co.contra-costa.ca.us/depart/cd/current/ConocoPhillipsDEIR_11_27_06/1%20-%20Introduction.pdf

14. Ibid, Torn

15. Ibid

16. http://articles.latimes.com/2001/jul/24/business/fi-25907

17. http://www.answers.com/topic/valero-energy-corp

18. http://www.tsocorp.com/stellent/groups/public/documents/published/tsi_bus_ref_t3__anacortes.hcsp

19. Final Environmental Impact Report for Chevron Products Company El Segundo Refinery Product Reliability and Optimization Project, http://www.aqmd.gov/ceqa/documents/2008/nonaqmd/chevron/PRO/chevronFND.html

20. Form 10-K, Chevron Corp – CVX, February, 28 2008, Annual report [Section 13 and 15(d), not S-K Item 405], page 25

21. ConocoPhillips Rodeo Refinery Clean Fuels Expansion Project, November 2006, page 1-1, ConocoPhillips Rodeo Refinery Clean Fuels Expansion Project

22. http://articles.latimes.com/2005/nov/17/business/fi-conoco17

23. BP Alaska Pipeline Shutdown- Impact on West Coast Refiners, http://www.fundamentalpetroleumtrends.com/sample_reports/update/PADD%205%20Crude%20Oil%20Supply%20081106.pdf

24. Ibid

25. "Heavy oil makes up approximately 80 percent of the crude oil production in the California fields" http://www.chevron.com/countries/usa/?view=2

26. Tesoro SEC presentation, 2007, http://209.85.173.132/search?q=cache:phOlQrAhwFQJ:www.secinfo.com/dsvrp.u1dp.a.htm+Shell+Wilmington,+crude+oil+Sulfur+content,+API&hl=en&ct=clnk&cd=3&gl=us

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28. U.S. Census Bureau, Zip Code Tabulation Area 90744, Census 2000 Demographic Profile Highlights

29. Fact Sheet, Hydrogen Sulfide, CAS # 7783-06-4, Agency for Toxic Substances and Disease Registry (ATSDR), http://www.atsdr.cdc.gov/tfacts114.pdf

30. Drilling Down, Natural Resources Defense Council, http://catskillpost.files.wordpress.com/2008/04/drillingdown_factsheet.pdf

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Most Recent Asthma State or Territory Data

These tables feature the latest national and state statistics on the burden of asthma among children and adults. The data are from national and state surveillance systems administered by the Centers for Disease Control and Prevention (CDC). Links to sources are provided with each table to assist with finding additional information on the data and relevant tables and reports.

See footnote for data source.

See also: National Data, Archived Most Recent Data

State or Territory Data

Adult Prevalence | Mortality

State or Territory
Adult Current Asthma[1] Prevalence by State or Territory (2021)

State or Territory	Number With Current Asthma	Percent With Current Asthma (SE)
Alabama	394,199	10.1 (0.62)
Alaska	49,453	9.0 (0.58)
Arizona	519,749	9.4 (0.39)
Arkansas	207,857	9.0 (0.62)
California	2,694,396	8.8 (0.45)
Colorado	476,932	10.4 (0.37)
Connecticut	300,910	10.5 (0.48)
Delaware	77,695	9.8 (0.69)
District of Columbia	64,298	11.6 (0.82)
Florida	—[2]	—[2]

State or Territory	Number With Current Asthma	Percent With Current Asthma (SE)
Georgia	772,663	9.4 (0.51)
Hawaii	92,849	8.1 (0.43)
Idaho	138,516	9.8 (0.46)
Illinois	860,395	8.7 (0.70)
Indiana	536,397	10.3 (0.39)
Iowa	224,466	9.1 (0.41)
Kansas	235,953	10.6 (0.31)
Kentucky	408,801	11.7 (0.59)
Louisiana	344,842	9.7 (0.60)
Maine	138,396	12.5 (0.47)
Maryland	451,158	9.4 (0.35)
Massachusetts	661,306	11.7 (0.52)
Michigan	908,568	11.5 (0.45)
Minnesota	387,219	8.8 (0.28)
Mississippi	226,646	10.0 (0.67)
Missouri	449,253	9.4 (0.42)
Montana	83,698	9.7 (0.48)
Nebraska	122,491	8.2 (0.33)
Nevada	223,954	9.1 (0.80)
New Hampshire	136,025	12.1 (0.60)
New Jersey	646,963	8.9 (0.46)
New Mexico	173,518	10.6 (0.53)
New York	1,563,485	9.8 (0.28)
North Carolina	717,344	8.7 (0.51)
North Dakota	50,012	8.4 (0.50)
Ohio	955,568	10.4 (0.38)

State or Territory	Number With Current Asthma	Percent With Current Asthma (SE)
Oklahoma	326,087	10.9 (0.54)
Oregon	377,851	11.2 (0.53)
Pennsylvania	1,062,292	10.3 (0.51)
Rhode Island	111,498	12.6 (0.62)
South Carolina	372,607	9.2 (0.45)
South Dakota	55,927	8.3 (0.78)
Tennessee	558,276	10.3 (0.59)
Texas	1,854,306	8.4 (0.45)
Utah	231,080	9.7 (0.38)
Vermont	61,465	11.8 (0.61)
Virginia	661,945	9.8 (0.41)
Washington	641,131	10.5 (0.36)
West Virginia	171,141	12.1 (0.50)
Wisconsin	498,228	10.8 (0.59)
Wyoming	43,188	9.7 (0.67)
Guam	4,997	4.7 (0.78)
Puerto Rico	311,148	11.4 (0.66)
Virgin Islands	3,920	5.0 (1.02)

Abbreviation: SE = Standard Error.
[1]Persons who answered "yes" to the questions: "Have you EVER been told by a doctor or other health professional that you had asthma?" and "Do you still have asthma?"
[2]Minimum data collection requirements were not met.
Source: 2021 Behavioral Risk Factor Surveillance System (BRFSS).

State
Asthma Mortality by State (2021)

State	Number of Deaths[1]	Crude Death Rate (SE)[1] Per Million	Adjusted Death Rate (SE)[1,2] Per Million
Alabama	67	13.3 (1.62)	11.6 (1.46)
Alaska	11	—[3] (4.53)	—[3] (4.87)

State	Number of Deaths[1]	Crude Death Rate (SE)[1] Per Million	Adjusted Death Rate (SE)[1,2] Per Million
Arizona	89	12.2 (1.30)	10.3 (1.12)
Arkansas	37	12.2 (2.01)	11.2 (1.90)
California	352	9.0 (0.48)	8.2 (0.44)
Colorado	49	8.4 (1.20)	7.6 (1.11)
Connecticut	35	9.7 (1.64)	8.5 (1.50)
Delaware	15	—[3] (3.86)	—[3] (3.73)
District of Columbia	14	—[3] (5.58)	—[3] (5.64)
Florida	204	9.4 (0.66)	8.0 (0.59)
Georgia	107	9.9 (0.96)	9.4 (0.93)
Hawaii	24	16.7 (3.40)	13.7 (2.91)
Idaho	16	—[3] (2.10)	—[3] (1.99)
Illinois	124	9.8 (0.88)	9.1 (0.83)
Indiana	70	10.3 (1.23)	9.4 (1.15)
Iowa	39	12.2 (1.96)	11.1 (1.84)
Kansas	37	12.6 (2.07)	12.5 (2.10)
Kentucky	22	4.9 (1.04)	4.0 (0.89)
Louisiana	45	9.7 (1.45)	9.3 (1.42)
Maine	—[4]	—[4]	—[4]
Maryland	79	12.8 (1.44)	11.2 (1.29)
Massachusetts	78	11.2 (1.26)	9.8 (1.15)
Michigan	94	9.4 (0.96)	8.6 (0.92)
Minnesota	58	10.2 (1.33)	8.5 (1.15)
Mississippi	45	15.3 (2.27)	15.3 (2.32)
Missouri	75	12.2 (1.40)	11.5 (1.36)
Montana	—[4]	—[4]	—[4]

State	Number of Deaths[1]	Crude Death Rate (SE)[1] Per Million	Adjusted Death Rate (SE)[1,2] Per Million
Nebraska	25	12.7 (2.55)	11.4 (2.33)
Nevada	28	8.9 (1.68)	8.3 (1.61)
New Hampshire	11	—[3] (2.39)	—[3] (2.47)
New Jersey	119	12.8 (1.18)	11.8 (1.11)
New Mexico	26	12.3 (2.41)	10.3 (2.07)
New York	248	12.5 (0.79)	10.6 (0.69)
North Carolina	108	10.2 (0.98)	8.9 (0.88)
North Dakota	10	—[3] (4.08)	—[3] (4.52)
Ohio	124	10.5 (0.95)	9.8 (0.91)
Oklahoma	47	11.8 (1.72)	11.0 (1.64)
Oregon	67	15.8 (1.93)	13.0 (1.64)
Pennsylvania	143	11.0 (0.92)	9.3 (0.82)
Rhode Island	—[4]	—[4]	—[4]
South Carolina	71	13.7 (1.62)	12.3 (1.52)
South Dakota	—[4]	—[4]	—[4]
Tennessee	83	11.9 (1.31)	11.3 (1.27)
Texas	295	10.0 (0.58)	10.1 (0.60)
Utah	24	7.2 (1.47)	8.6 (1.78)
Vermont	—[4]	—[4]	—[4]
Virginia	85	9.8 (1.07)	9.1 (1.01)
Washington	85	11.0 (1.19)	10.1 (1.11)
West Virginia	16	—[3] (2.24)	—[3] (1.98)
Wisconsin	67	11.4 (1.39)	10.1 (1.26)
Wyoming	10	—[3] (5.46)	—[3] (4.75)
Total	3,517	10.6 (0.18)	9.5 (0.16)

[1]Underlying cause of death is asthma (ICD-10 codes: J45–J46).
[2]Population-based rates are age-adjusted to the 2000 standard population.
[3]Rates are unreliable when the number of deaths is less than 20.
[4]Data are suppressed when the number of deaths is 9 or fewer.

Source: CDC/NCHS, Division of Vital Statistics CDC Wonder

Last Reviewed: May 10, 2023

INSIDE

PETROLEUM NEWS

REFINING NEWS

- **PBF Torrance**: On January 20, an emergency flaring event took place.
- **Valero Wilmington**: On January 25 through February 1, the refinery experienced flaring due to planned maintenance.
- **Chevron El Segundo**: On January 30, an emergency flaring event took place.
- **Chevron Richmond**: On February 10, a flaring event took place due to a process upset in one of the units, prompting precautionary evacuations of less than 100 people.

GASOLINE RETAIL PRICES BY BRAND

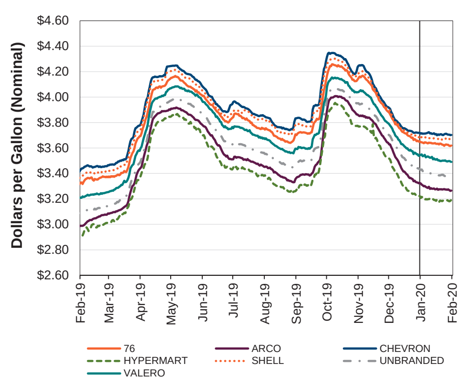
January 2020 vs. 2019

(Percentage Change)

76	8% higher
ARCO	8% higher
Chevron	7% higher
Hypermart	8% higher
Shell	8% higher
Unbranded	8% higher
Valero	8% higher

January 2020 Averages

76	$3.63
ARCO	$3.28
Chevron	$3.71
Hypermart	$3.19
Shell	$3.68
Unbranded	$3.40
Valero	$3.51



Source: California Energy Commission (CEC) analysis of Oil Price Information Service (OPIS) data

DIESEL RETAIL PRICES BY REGION

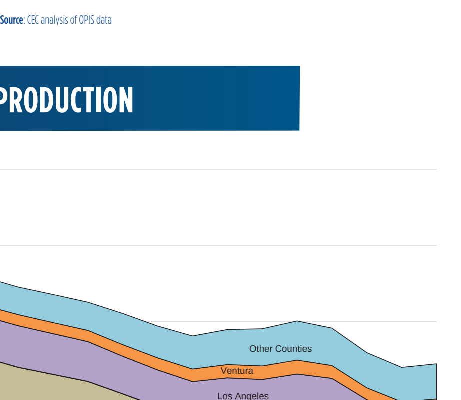
January 2020 vs. 2019

(Percentage Change)

Northern CA	3% higher
Central CA	2% lower
Southern CA	3% higher

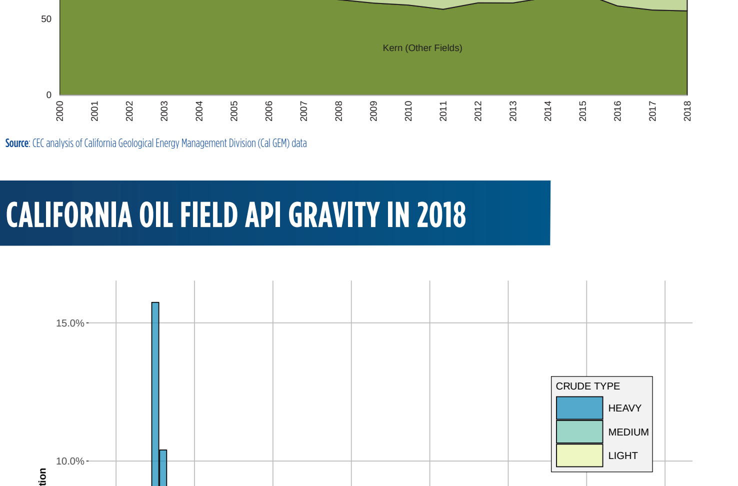
January 2020 Averages

Northern CA	$3.77
Central CA	$3.67
Southern CA	$3.88

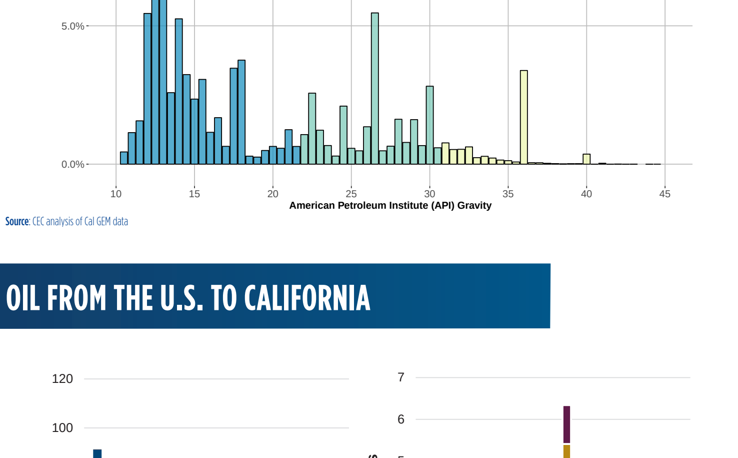


Source: CEC analysis of OPIS data

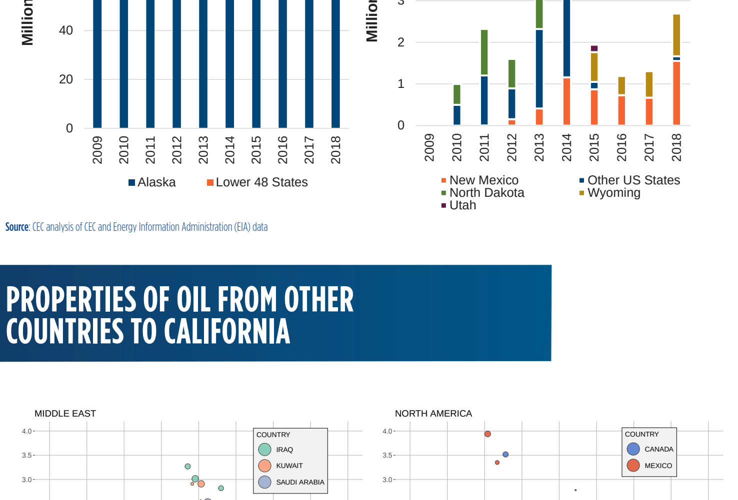
CALIFORNIA OIL FIELD PRODUCTION



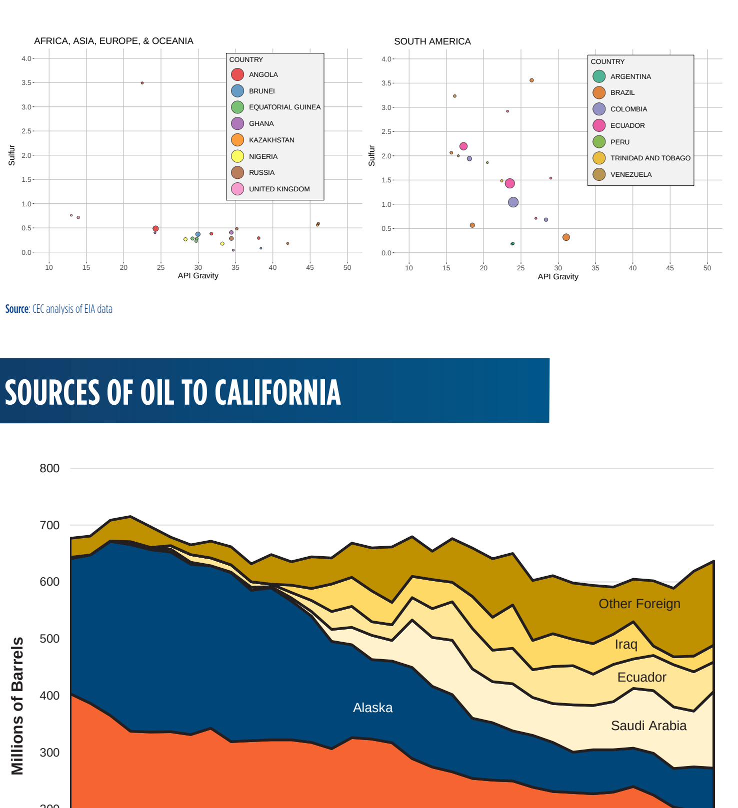
CALIFORNIA OIL FIELD API GRAVITY IN 2018



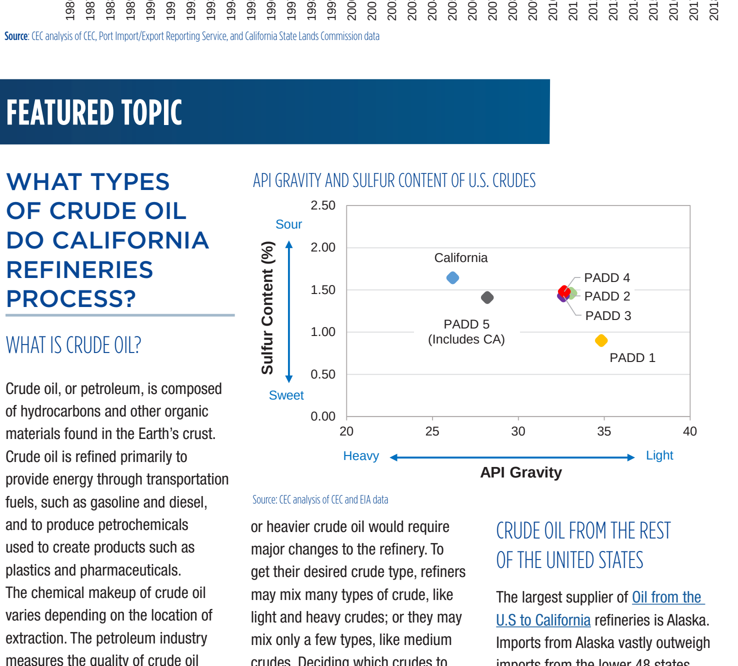
OIL FROM THE U.S. TO CALIFORNIA



PROPERTIES OF OIL FROM OTHER COUNTRIES TO CALIFORNIA



SOURCES OF OIL TO CALIFORNIA



FEATURED TOPIC

WHAT TYPES OF CRUDE OIL DO CALIFORNIA REFINERIES PROCESS?

WHAT IS CRUDE OIL?

Crude oil, or petroleum, is composed of hydrocarbons and other organic materials found in the Earth's crust. Crude oil is refined primarily to provide energy through transportation fuels, such as gasoline and diesel, and to produce petrochemicals used to create products such as plastics and pharmaceuticals. The chemical makeup of crude oil varies depending on the location of extraction. The petroleum industry measures the quality of crude oil using the following properties: specific gravity, sulfur content, acid content, nitrogen, viscosity, pour point, mercaptan, hydrogen sulfide, metals, and organic chlorides.[1]

The most widely reported crude properties are specific gravity and sulfur content. Specific gravity measures the density of a substance compared to water. The petroleum industry uses the American Petroleum Institute (API) gravity scale, which sets the density of water at 10 degrees. A refinery will use API gravity to categorize crude oil as light (more than 31.1 degrees), medium (22.3 to 31.1 degrees), heavy (10 to less than 22.3 degrees), or extra heavy (less than 10 degrees).[2] Crude that is on the heavier, more viscous side of the API gravity scale is denser. Extracting a heavy crude (with for example an API gravity of 12) from the ground is like trying to drink a milkshake through a thin straw.

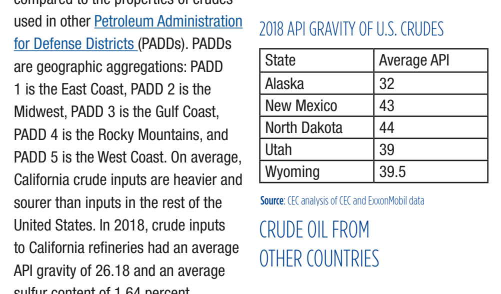
Sulfur content of crude oil is measured by the percentage of sulfur within crude. Higher sulfur content in crude oil is undesirable because transportation fuels have a sulfur content limit due to the formation of harmful sulfur oxides when sulfur burns. Also, because sulfur is corrosive, crude oil that has high sulfur content is more damaging to refinery equipment and pipelines. Crude oil is considered sweet if sulfur content is 0.5 percent or less, and sour if sulfur content is more than 0.5 percent.[3]

The properties of crude oil are used to help determine its market value. Crude oil that is light and sweet is usually more expensive than crude that is heavy and sour. A reason for this is that light sweet crudes are less energy-intensive to refine than heavy sour crude. Refiners mix many types of crude oil from both foreign and domestic sources to achieve their desired crude profile.

WHAT KIND OF CRUDE OIL GOES INTO CALIFORNIA REFINERIES?

Refiners work towards processing crudes with similar properties because a significant shift to a lighter or heavier crude oil would require major changes to the refinery. To get their desired crude type, refiners may mix many types of crude, like light and heavy crudes; or they may mix only a few types, like medium crudes. Deciding which crudes to mix depends on factors like price, availability, and refinery maintenance.

API GRAVITY AND SULFUR CONTENT OF U.S. CRUDES



Source: CEC analysis of CEC and EIA data

The API Gravity and Sulfur Content of U.S. Crudes chart displays properties of crudes used by California refineries compared to the properties of crudes used in other Petroleum Administration for Defense Districts (PADDs). PADDs are geographic aggregations: PADD 1 is the East Coast, PADD 2 is the Midwest, PADD 3 is the Gulf Coast, PADD 4 is the Rocky Mountains, and PADD 5 is the West Coast. On average, California crude inputs are heavier and sourer than inputs in the rest of the United States. In 2018, crude inputs to California refineries had an average API gravity of 26.18 and an average sulfur content of 1.64 percent.

SOURCES OF CRUDE OIL TO CALIFORNIA REFINERIES

In 2018, California refineries received 31.1 percent of their crude from California, 11.4 percent from Alaska, and 57.5 percent from foreign sources. Sources of Oil to California displays the top suppliers of crude. The top three foreign sources are Saudi Arabia, Ecuador, and Iraq. Foreign sources of crude are increasing because California and Alaska oil fields are aging. As the oil fields become older and depleted, extracting crude oil becomes more difficult. Foreign imports supplement declining domestic sources.

CALIFORNIA'S CRUDE OIL

California crude oil production in 2018 breaks down into the following API gravity categories: 68 percent of crude oil is heavy, 24 percent is medium, and the remaining 8 percent is light. California Oil Field API Gravity in 2018 shows the distribution of API gravity for California crudes.

California Oil Field Production breaks down production by county and region. Kern County produces the most in California, with 65.7 percent of total oil in 2018 originating from Kern oil fields. The top three producing oil fields in Kern County are Midway-Sunset (12 percent), Belridge-South (12 percent), and Kern River (9.5 percent). Together, the three fields extract about as much oil as the rest of the producing counties combined.

CRUDE OIL FROM THE REST OF THE UNITED STATES

The largest supplier of Oil from the U.S to California refineries is Alaska. Imports from Alaska vastly outweigh imports from the lower 48 states. The other largest suppliers of oil to California are New Mexico, North Dakota, Utah, and Wyoming. The 2018 API Gravity of U.S. Crudes fall within the light crude category.

2018 API GRAVITY OF U.S. CRUDES

State	Average API
Alaska	32
New Mexico	43
North Dakota	44
Utah	39
Wyoming	39.5

Source: CEC analysis of CEC and ExxonMobil data

CRUDE OIL FROM OTHER COUNTRIES

There are many reasons why California refineries import different types of crude oil, but all are rooted in meeting refinery needs. Properties of Oil from Other Countries to California shows the major crude supplying countries by color and import volumes are represented by the size of the circle. In 2018, California refineries imported foreign oil from three major regions: Middle East, South America, and North America. The largest supplier of light crude to California is Saudi Arabia, with 134.8 million barrels. Other large suppliers from the Middle East are Iraq (29.8 million barrels) and Kuwait (22.5 million barrels), which are also light crude sources. All crude oil coming out of the Middle East is sour, having a sulfur content greater than 0.5 percent.

As production in California oil fields has declined, California refineries have filled their need for heavy crude oil by increasing imports from South America. The largest supplier of crude oil from the region is Ecuador (51.8 million barrels), primarily supplying heavy crude. The next largest supplier is Colombia with an API gravity of 18 to 28 degrees. Brazil is the final major supplier in the region, providing 17.6 million barrels as two distinct crudes, a heavy crude (15 to 18 API) and a medium crude (26 to 31 API). Crude from North America consists of small quantities from Canada (10.9 million barrels) and Mexico (15 million barrels) with the majority of crude oil being heavy and with sulfur content around 2 percent. Refiners source the remaining crude from Africa, Asia, Europe, and Oceania, which ranges in crude properties.

1 McKinsey Energy Insights, Qualities (crude) https://www.mckinseyenergyinsights.com/resources/refinery-reference-desk/qualities-crude
2 API Gravity http://www.petroleum.co.uk/api
3 Sweet vs. Sour Crude Oil http://www.petroleum.co.uk/sweet-vs-sour

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INSIDE

REFINERY NEWS

- No news to report

CALIFORNIA GASOLINE RETAIL PRICES BY BRAND

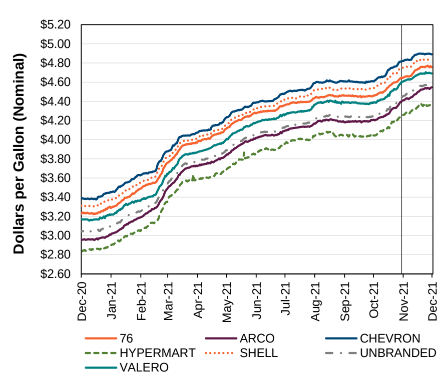
November 2021 vs. 2020

(Percentage Change)

76	46% higher
ARCO	52% higher
Chevron	44% higher
Hypermart	53% higher
Shell	45% higher
Unbranded	49% higher
Valero	48% higher

November 2021 Averages

76	$4.72
ARCO	$4.49
Chevron	$4.87
Hypermart	$4.33
Shell	$4.81
Unbranded	$4.53
Valero	$4.66



Source: California Energy Commission (CEC) analysis of Oil Price Information Service (OPIS) data

CALIFORNIA DIESEL RETAIL PRICES BY REGION

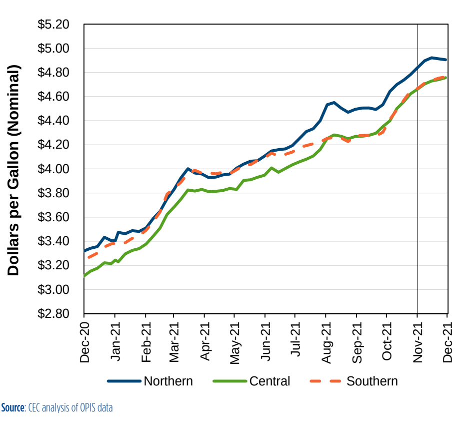
November 2021 vs. 2020

(Percentage Change)

Northern CA	49% higher
Central CA	55% higher
Southern CA	49% higher

November 2021 Averages

Northern CA	$4.90
Central CA	$4.71
Southern CA	$4.72



Source: CEC analysis of OPIS data

CALIFORNIA COUNTIES WITH THERMAL ENHANCED OIL RECOVERY (EOR) OIL FIELDS

County	Fields with Steam Wells	Steam Wells	Water Flood Wells	Extracting Wells	Total Field Production (Barrels)
Kern	15	22,288	2,448	24,447	80,596,049
Monterey	2	316	15	1,023	6,779,357
Fresno	1	1,254	40	1,424	5,010,949
Los Angeles	2	60	616	1,260	4,772,255
Santa Barbara	2	285	64	578	1,743,162
Orange*	2	3	104	376	833,631
San Luis Obispo	1	70	0	214	405,618
Ventura	1	11	0	20	94,214

Source: CEC analysis of California Geologic Energy Management Division (CalGEM) data

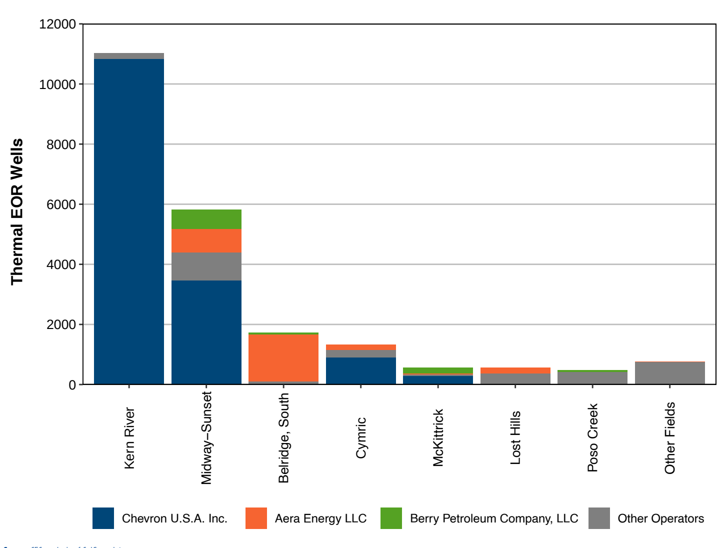
Notes: Orange County includes off shore oil fields.

KERN COUNTY THERMAL EOR OIL FIELDS

Kern Field	Steam Wells	Water Flood Wells	Extracting Wells	Total Field Production (Barrels)
Midway-Sunset	5,831	2	6,538	16,537,713
Kern River	11,024	0	1,537	15,873,431
Belridge, South	1,725	1,264	6,047	15,831,842
Cymric	1,330	0	1,181	8,602,410
Lost Hills	560	667	3,115	8,251,732
Poso Creek	483	9	1,019	3,859,240
McKittrick	564	0	594	3,228,727
Kern Front	304	0	1,145	2,784,164
Round Mountain	180	164	622	2,281,639
Belridge, North	10	263	972	1,393,325
Mount Poso	6	70	664	1,026,513
Edison	231	9	767	550,839
Antelope Hills, North	15	0	70	191,879
Asphalto	9	0	112	134,845
Chico-Martinez	16	0	64	47,750

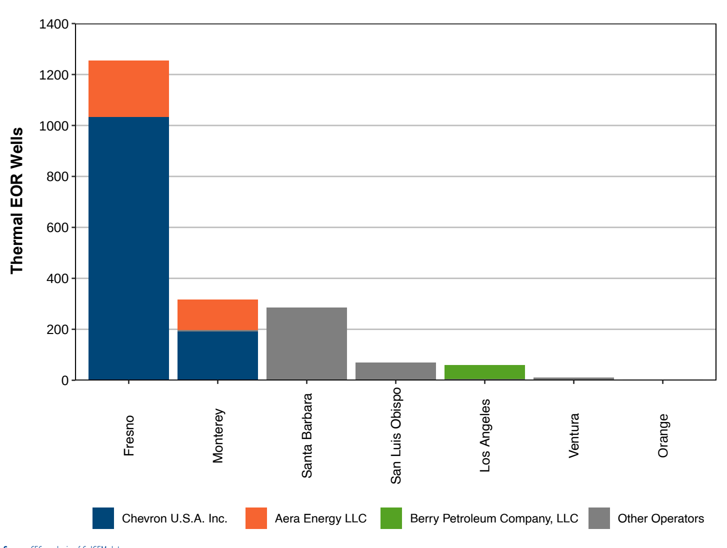
Source: CEC analysis of CalGem data

THERMAL EOR WELLS AT OIL FIELDS IN KERN COUNTY IN 2020



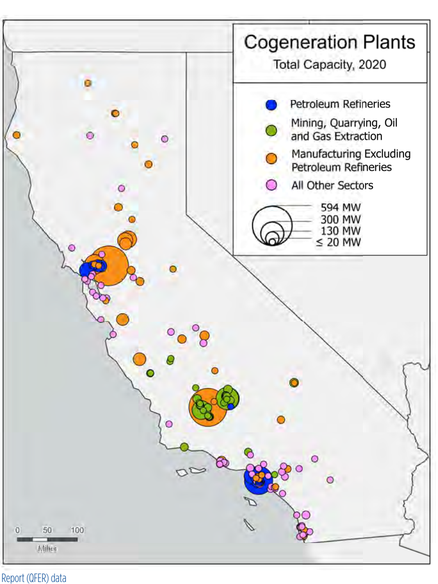
Source: CEC analysis of CalGem data

THERMAL EOR WELLS AT OIL FIELDS OUTSIDE OF KERN COUNTY IN 2020



Source: CEC analysis of CalGEM data

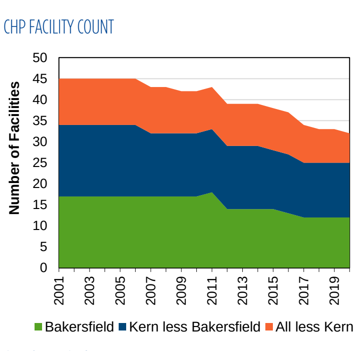
COMBINED HEAT AND POWER (CHP) LOCATIONS AND CAPACITY



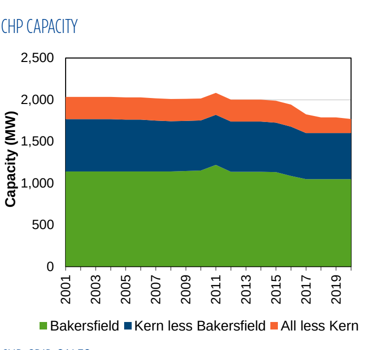
Source: CEC Quarterly Fuel and Energy Report (QFER) data

CHP FACILITY COUNT, CAPACITY, GENERATION, AND GRID SALES

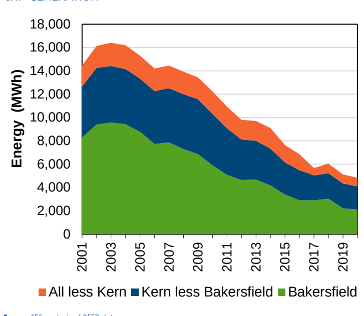
CHP FACILITY COUNT



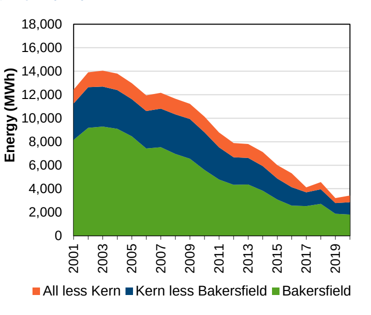
CHP CAPACITY



CHP GENERATION



CHP GRID SALES



Source: CEC analysis of QFER data

FEATURED TOPIC

CALIFORNIA OIL FIELDS WITH THERMAL ENHANCED OIL RECOVERY

Thermal enhanced oil recovery (EOR) is an important part of California's oil production, aiding in the recovery of crude oil remaining in wells after extraction. Thermal EOR is a process of injecting pressurized steam into oil reservoirs to lower the viscosity of, or thin, heavy oil to increase the flow and the amount of recoverable crude oil. There are two steam injection methods: steamflooding and cyclic steaming. Steamflooding uses separate wells to inject steam that will heat up the oil and allow it to flow to the extraction well. Cyclic steaming is a single well operation where steam is injected into the oil well, left in place to soak, then pumped out before crude is extracted; the process repeats in cycles. Steamflooding and cyclic steaming increases the amount of recoverable crude oil from fields with heavy crudes that have low API gravity, like those typically found in California (see February 2020 Petroleum Watch). Thermal EOR is a type of tertiary recovery, the other types being gas injection and chemical injection, discussed in the November 2020 Petroleum Watch.

Thermal EOR is the most common method of tertiary recovery performed in California. According to a 2017 International Energy Agency survey, 96.5 percent of thermal EOR performed in the United States is performed in California. California is home to some of the nation's oldest oil wells, with the commercial production in the San Joaquin basin dating back to 1887 and thermal EOR introduced in the 1960s. Now, approximately 77 percent of California's crude oil production comes from fields with steam wells. According to the California Geologic Energy Management Division (CalGEM), in 2020, over 100 million barrels of crude oil production came from fields with steam wells out of California's total crude oil production of approximately 130 million barrels.

THERMAL EOR IS LOCATION SPECIFIC

California has extracting oil wells in 15 counties, but thermal EOR is only used in eight counties. California Counties with Thermal Enhanced Oil Recovery (TEOR) Oil Fields shows the counties in California that have steam wells, along with additional details like the number of fields that have steam wells and production quantity for 2020. Kern County is home to the most steam wells, just under 22,300 wells. The only other county with more than a thousand steam wells is Fresno, with 1,254 wells. Kern County also has the greatest amount of crude oil production from fields with steam wells, producing nearly 12 times the amount as the second ranked county, Monterey.

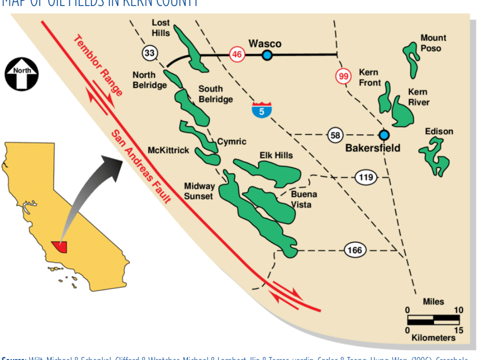
California has 532 oil fields, 337 of those are non-producing. Of the 195 fields with production, only 26 have thermal EOR. Kern County Thermal EOR Oil Fields shows the individual fields in Kern County, along with the number of steam wells, waterflood wells, extracting wells, and production. While the Kern River Oil Field has the greatest number of steam wells, it has fewer extraction wells than Midway-Sunset, the topped ranked field in Kern County by production. South Belridge has fewer steam wells but the most waterflood wells in the fields analyzed, which contributes to its rank as third highest by production. The field with the most steam wells outside of Kern County is Coalinga Oil Field in Fresno County. The field with the highest production outside Kern County is the San Ardo Oil Field, located in Monterey County. Nearly 99 percent of steam wells and oil production from steam wells within Monterey County comes from the San Ardo oil field.

THERMAL EOR OPERATORS

Thermal EOR Wells at Oil Fields in Kern County in 2020 shows the number of steam wells by operator in Kern County by oil field. Thermal EOR Wells at Oil Fields Outside of Kern County in 2020 shows the number of steam wells by operator in all other counties. Most steam wells are operated by just a few companies, the largest being Chevron, Aera Energy LLC, and Berry Petroleum. These companies combine for 68 percent of production from fields that have steaming.

In Kern County, large companies dominate the large oil fields. Chevron has the greatest number of thermal EOR wells in Kern River, Midway-Sunset, Cymric, and McKittrick. Aera is the largest operator in South Belridge, but also has wells in Midway-Sunset, Cymric, and Lost Hills. Berry Petroleum operates in Midway-Sunset, McKittrick, and Poso Creek. However, smaller operators can have a greater presence in smaller fields. For example, E&B Natural Resources Management Corporation is the other operator in Poso Creek and has the most steam wells in that field. "Other Fields" consists of eight additional oil fields.

MAP OF OIL FIELDS IN KERN COUNTY



Source: Wilt, Michael & Schenkel, Clifford & Wratcher, Michael & Lambert, Ilia & Torres-verdin, Carlos & Tseng, Hung-Wen. (1996). Crosshole EM for Oil Field Characterization and EOR Monitoring: Field Examples from Lost Hills, California.

There are 22 "Other Operators" with steam wells. Sentinel Peak Resources California LLC (Sentinel) is the largest of the other operators by number of steam wells, has presence in four fields, and is the only operator in San Luis Obispo County. California Resource Production Company is the next largest. While it has presence in six fields, it predominantly operates in Kern Front. All the remaining companies have steam wells in three fields or less, with the most frequent number of fields being one. There are nine different operators in Midway-Sunset, six in McKittrick, four in Lost Hills, and all the remaining fields have three or fewer.

As mentioned previously, thermal EOR operations outside of Kern County only occur in one or two fields per county. For example, nearly all steam wells in Fresno County are in the Coalinga Oil Field, and nearly all steam wells in Monterey County are in the San Ardo Oil Field. Operator presence in these large fields is dominated by the major oil operators, Chevron and Aera. Operations in Santa Barbara has the most diversity with four different operators.

OIL FIELDS IN KERN COUNTY

More than a dozen active oil fields are in Kern County. The Map of Oil Fields in Kern County shows a selection of those fields. Kern River and Kern Front are located just to the east of central Bakersfield. South Belridge, Cymric, McKittrick, and Midway-Sunset run from north to south on the western side of the county. Elk Hills, located adjacent to these fields to the east, is unique in that, in addition to oil, it is responsible for more than half (53.5 percent) of in-state natural gas production, according to the CalGEM 2019 Annual Report. California's demand for natural gas is far greater than what it produces in state; nearly 90 percent of natural gas used in California is imported.

CHP USED FOR THERMAL EOR

Steam for the oil fields is traditionally produced using either boilers or combined heat and power (CHP). CHP, also known as cogeneration, is the simultaneous production of electricity and thermal energy, where the thermal energy is then used for an industrial process. In this case, the thermal energy is used for thermal EOR. (Concentrated solar powered steam tubes are used as well but are newer and infrequently used.) Since boilers and CHP are both fueled by natural gas, the economics of steaming are mainly a function of the price of natural gas and the price of crude oil.

Combined Heat and Power (CHP) Locations and Capacity is a map of all the CHP facilities located in California that are one megawatt or larger. The facilities are color coded by their North American Industry Classification System (NAICS) code. Except for one mining facility, which is the farthest to the east, all other mining, quarrying, and oil and natural gas extraction facilities are used for oil and natural gas extraction. Most CHP facilities used for thermal EOR are in two general regions: east of Bakersfield and the west side of Kern County.

In 2020, Kern County was home to 25 facilities with a cumulative capacity of 1,601 megawatts (MW). Most of those facilities are in Bakersfield, which is home to 12 facilities and 1,048 MW of generation capacity. Six of those are in the Kern River Oil Field (857 MW), four are in Kern Front (191 MW), and the remaining facilities are in Mt. Poso and Kern Bluff with one apiece.

The 13 facilities outside of Bakersfield are located on the west side of Kern County. Six are in the Midway-Sunset Oil Field (353 MW), three are in the McKittrick Oil Field (63 MW), and the remaining four are spread among South Belridge, Elk Hills, Cymric, and Lost Hills (137 MW combined). Notably, Elk Hills is the only field with thermal EOR CHP that does not currently have any active steam wells. In addition to the thermal EOR CHP facilities, there is a large CHP facility (567 MW) located in Elk Hills whose NAICS code indicates that it is used for natural gas processing (orange in color for other manufacturing). The top eight fields in Kern County ranked by number of steam wells all have thermal EOR CHP.

The remaining counties (consisting of Fresno, Los Angeles, Monterey, Orange, and Santa Barbara) each have one or two facilities, totaling seven facilities with a combined capacity of 170 MW. This brings the total number of CHP facilities used for thermal EOR in 2020 to 32 with a cumulative capacity of 1,771 MW.

THERMAL EOR CHP OPERATION

CHP Facility Count, Capacity, Generation, and Grid Sales contains four time-series of CHP used for thermal EOR. Each graph is broken out into three categories: those located in Bakersfield, those outside Bakersfield but in Kern County, and those outside Kern County.

While the number of facilities has decreased by nearly a quarter over the past decade, and most of that has occurred in Kern County, it is still home to the majority of thermal EOR facilities. The decline in facility count is greater than the decline in generation capacity, which means that while there are fewer facilities now, they tend to be larger in size.

While the steam generated at these CHP facilities is used onsite, most of the electricity generated is exported to the grid. Both Pacific Gas & Electric and Southern California Edison own multiple transmission lines that pass through Kern County, allowing electricity from these facilities to move to load centers to the north and south of the state. The percentage of electricity sold to the grid has declined over time but is still mostly exported. The percent of electricity sold to the grid was around 86 percent near the turn of the century, down to 83 percent in 2010, and 71 percent in 2020.

Capacity factor is the ratio of actual generation over potential generation if the plant operated at full capacity, typically expressed as a percent. Capacity factor is seen as the indicator of a plant's utility or how much it is being used. The capacity factor for thermal EOR CHP was as high as 92 percent in 2003 but has steadily declined since then to only 31 percent in 2020. While thermal EOR CHP facilities are exporting slightly less of their generation, they are generating significantly less in total. This is a long term downward trend, capacity factor had a bigger decline between 2018 and 2019 than between 2019 and 2020. The largest single year decline was between 2014 and 2015 (52% to 44%), which was mostly related to contract issues.

CONCLUSION

While not all oil fields in California use thermal EOR, those that do play an outsized role in oil production within the state. Thermal EOR is concentrated in a limited number of oil fields in the United States, mostly found in Kern County and its neighboring counties.

Essentially, thermal EOR CHP facilities burn imported natural gas to help extract petroleum locally. California has policies in place to phase out both natural gas for electricity generation and petroleum for passenger vehicles. These policies include Governor Newsom's Executive Order calling for elimination of new internal combustion passenger vehicles by 2035, and Senate Bill 100 requiring renewable energy and zero-carbon resources to supply 100 percent of electric retail sales to end-use customers by 2045.

With a few exceptions, most thermal EOR CHP facilities were built between 1982 and 1995, so the newer facilities are 26 years old, and the oldest facilities are approaching 40 years. Staff anticipates that more facilities will retire in the coming years as equipment reaches the end of its life expectancy.

However, in the near-term, these CHP facilities provide system reliability by maintaining their generation capacity and providing energy during peak demand hours. Transmission assets that were built to bring electricity from these CHP facilities to the rest of the state could instead be used to bring renewable generation from solar power plants built in the region. To meet its clean energy goals, the state must navigate a stable transition away from fossil fuels. This requires managing the retirement of CHP resources in the region, supporting renewable energy deployment, and utilizing legacy transmission assets, all while maintaining a dependable electricity supply.

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Twitter LinkedIn Instagram Facebook YouTube Flickr https://www.bakersfield.com/news/state-finds-27-oil-wells-leaking-methane-in-arvin-lamont-area/article_52120332-00da-11ee-b466-83e7f8b280c5.html

State finds 27 oil wells leaking methane in Arvin-Lamont area

BY JOHN COX jcox@bakersfield.com
Jun 1, 2023

In this Californian file photo, an oil pumping unit and storage tank near Shane Court in Arvin is surrounded by residential apartments, single-family homes and commercial businesses.

Californian file photo

Leaky oil wells are raising health and safety concerns in Kern County again after inspectors found 27 sites in the Arvin-Lamont area — 40% of the total tested recently by a state task force — were emitting methane unchecked.

The findings unsettled some members of the community after it was announced during a meeting Wednesday. On Thursday, environmental justice advocates called for additional testing and direct notification to neighbors.

Word of uncontrolled methane releases was a reminder of the 45 oil wells found to be leaking the potent greenhouse gas in and around Bakersfield last year. Those leaks have since been addressed — more than once, in several cases, owing to recurring leaks. Their discovery led state officials to convene the task force whose members identified the leaks disclosed this week.

A spokesman for the state's primary oil and gas regulator, the California Geologic Energy Management division, said by email Thursday that most of the wells' operators were present for the inspections and have since reported having repaired the leaks. He said state inspectors are being sent to confirm the repairs.

But in the case of 11 of the leaky wells, the parties responsible have indicated they do not intend to fix them. CalGEM spokesman Jacob Roper said those same operators have ignored state orders to properly plug the wells, and that the agency "is working on an emergency contract to have those wells fixed as soon as possible." He wrote that money to do so will come from a fund covered by industry fees.

Greater detail was not available from Wednesday's community presentation by CalGEM, the California Air Resources Board and the San Joaquin Valley Air Pollution Control District. But groups worried about the findings said it was stated at the meeting that the wells inspected were located within 3,200 feet of homes and schools in the Arvin-Lamont area. They said three of the wells found to be leaking are located within 1,000 feet of a school.

"Orphan and idle wells that are left unplugged and unmonitored are a ticking time bomb of health and safety risks consistently impacting communities in the Central Valley," stated a news release issued Thursday on behalf of environmental justice groups active in the region.

While methane releases have become a priority for state policymakers trying to address climate change, the concern at oil wells is different. Residents have expressed concerns the gas presents health risks as well as safety worries, even as officials say the leaks pose a minimal threat because the gas disperses quickly and does not accumulate enough to ignite.

Cesar Aguirre, a community organizer with the Central California Environmental Justice Network, said by email non-methane toxic and cancerous gases could still be in the air near the leaky wells. He noted that when similar releases were discovered in Bakersfield, state officials responded by taking samples and going door to door monitoring for methane.

"The governor and his agencies should treat Arvin and Lamont with the same respect" paid to Bakersfield residents, Aguirre wrote.

Byanka Santoyo, a community organizer with the Center on Race, Poverty & The Environment, said she was thankful state legislation has given communities such as Arvin special authority to take action against pollution in their areas.

"I think it's concerning," she said, "but at the same time, it is assuring that we do have that collaboration between the local enforcers, the state agencies and whoever is responsible for all these toxins that should be cleaned up."

A staff attorney with CRPE, Kayla Karimi, called the 40% rate of leakage "extremely alarming and unacceptable."

"These agencies must do more to ensure wells are being properly managed, and we must end neighborhood drilling to ensure our communities are safe," she said by email.

Editor's note: The headline on this story has been corrected to state 27 leaky oil wells were discovered.

MORE INFORMATION

+

State focuses on possible methane leaks at local oil wells

State considering changes after activists press for action on leaky oil wells

Activists, Kern officials agree on need to address leaky oil wells

State proposes plugging more than 100 orphan oil wells in Kern

Environmental report calls for accelerating oil well plugging

ENVIRONMENTAL HEALTH INVESTIGATIONS BRANCH

California Asthma Dashboard

Welcome to the California Asthma Dashboard. Here, you can view state- and county-level asthma data, print PDFs of charts, and download data sets for analysis. The interactive dashboard is organized into four sections:

1. **Statewide data (all asthma measures)** – state-level data on asthma prevalence (proportion of the population with asthma), emergency department (ED) visits, hospitalizations, insurers, and deaths
2. **Prevalence by county** – county-level data on asthma prevalence (proportion of the population with asthma)
3. **ED visits, hospitalizations, and insurers by county** – county-level data on asthma ED visits, hospitalizations, and insurers
4. **Deaths by county** – county-level data on asthma deaths

Dashboard Instructions (PDF) | Notes about the Data (PDF) | ADA Accessible Data File (Excel) | Data Analysis Files on Open Data Portal webpage | Additional Resources for Astham data (PDF)

*Note: The ADA Accessible Data File is not appropriate for data analysis because all fields are text. To download data sets for analysis, open Data Analysis Files on Open Data Portal webpage or go to the Download Charts and Data Sets section of the dashboard.

Click on the rectangular orange buttons below to navigate between asthma measures of interest.

Statewide data (all asthma measures) | Prevalence by county | ED visits, hospitalizations, and insurers by county | Deaths by county

Asthma Prevalence Within a County

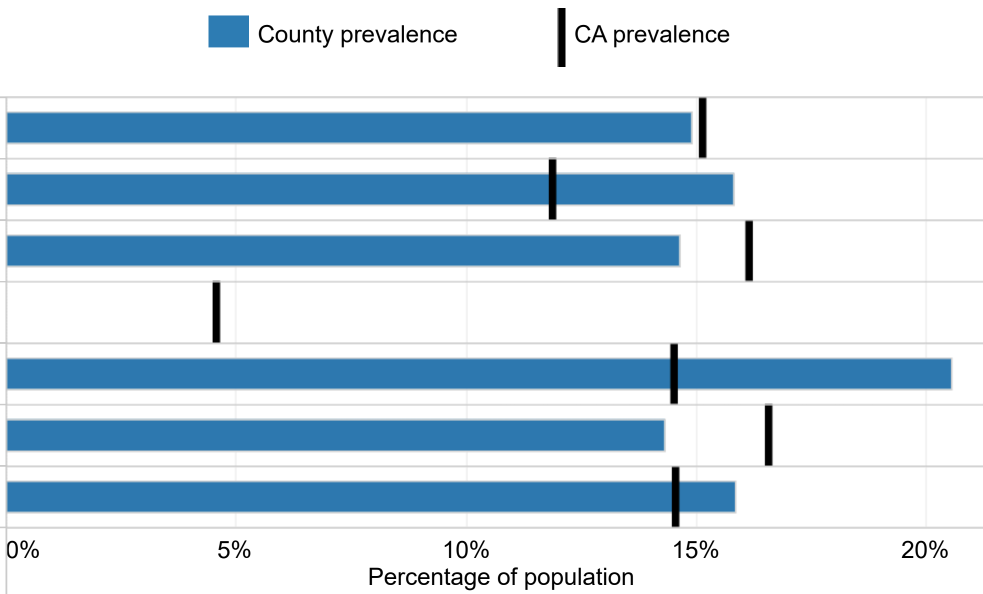
Prevalence is the proportion, or number of people out of the total population, affected by a particular disease or condition. It is commonly shown as a percentage of the population. For asthma, we refer to two types of prevalence:

- **Lifetime asthma prevalence** is the proportion of people who have ever been diagnosed with asthma by a healthcare provider
- **Active asthma prevalence** is the proportion of people who have ever been diagnosed with asthma by a healthcare provider AND report they still have asthma and/or had an episode or attack within the past 12 months

Make selections: County: Alameda | Type of prevalence: Lifetime asthma prevalence | Years: 2019–2020

Percentage ever diagnosed with asthma in Alameda County, by age group (2019–2020)

Comparison	Group	% of County Population	% of CA Population
Total population	All ages	14.9%	15.1%
Children vs. adults	0–17 years	15.8%	11.9%
	18+ years	14.6%	16.2%
Age group	0–4 years	Not available	4.6%
	5–17 years	20.5%	14.5%
	18–64 years	14.3%	16.6%
	65+ years	15.9%	14.6%



Bars are missing on chart and values are marked as "Not available" when not enough data are available to calculate prevalence.

Certain counties with small populations are grouped together for analysis of prevalence data:

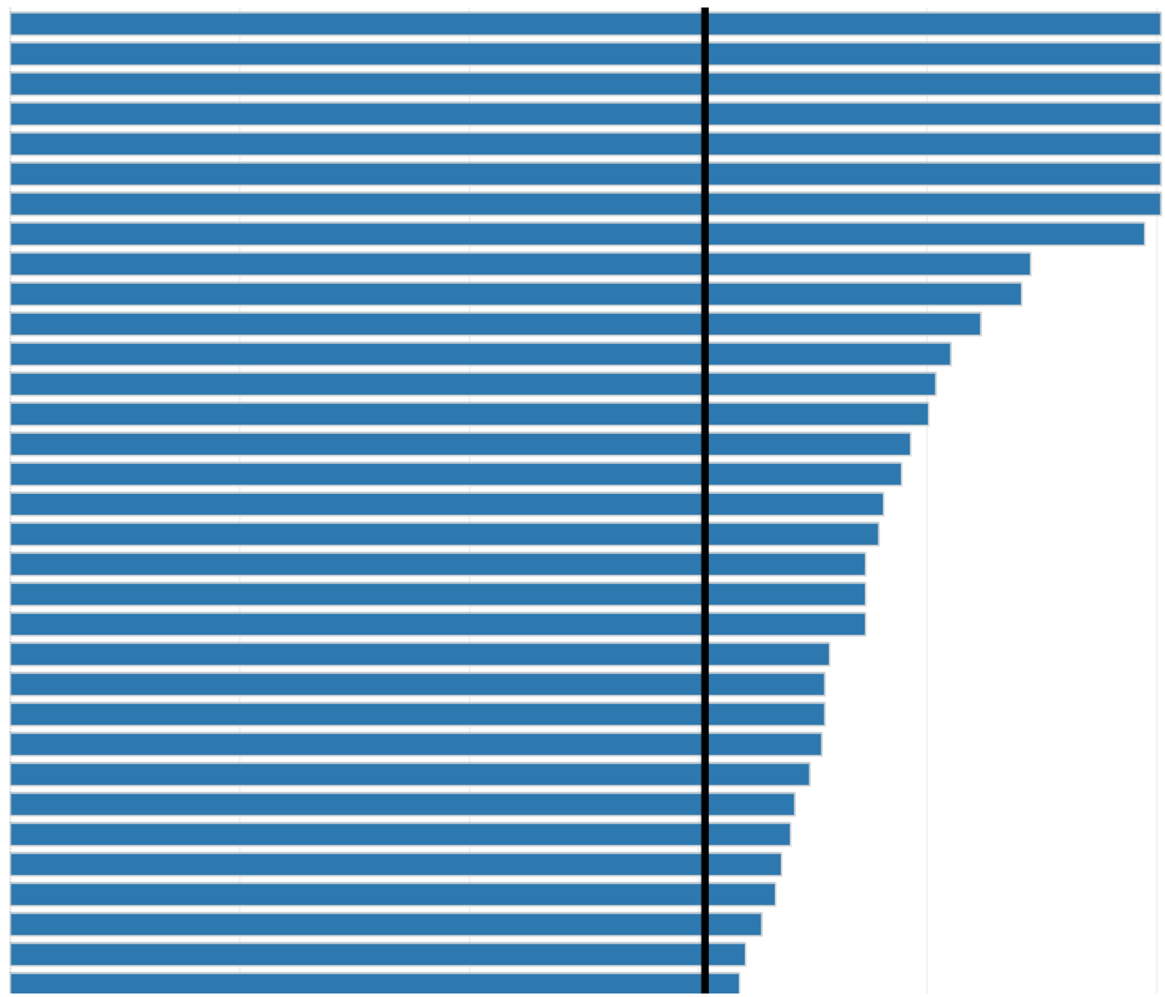
- Alpine, Amador, Calaveras, Inyo, Mariposa, Mono, and Tuolumne counties are combined
- Colusa, Glenn, and Tehama counties are combined
- Del Norte, Lassen, Modoc, Plumas, Sierra, Siskiyou, and Trinity counties are combined

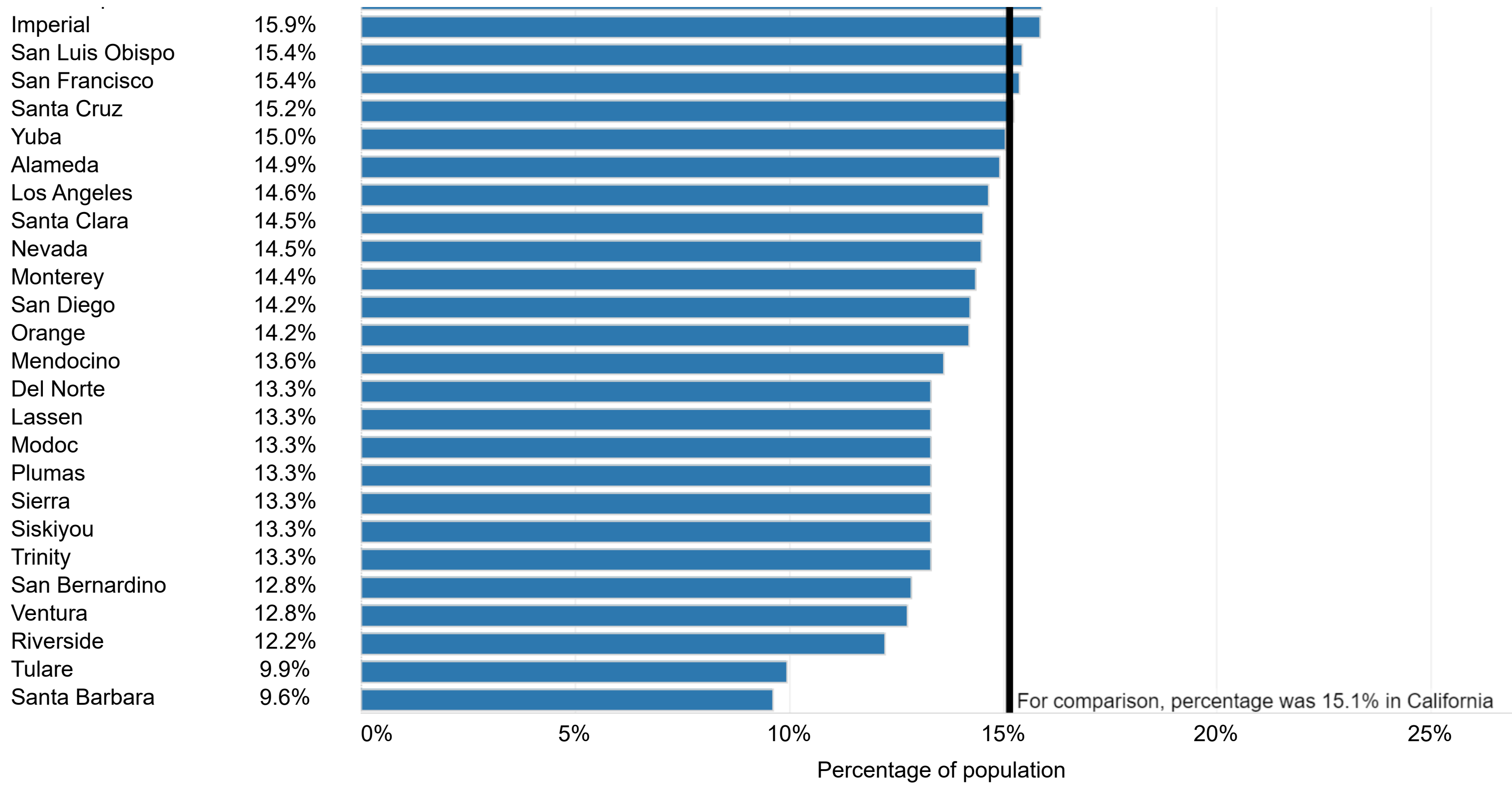
Asthma Prevalence Across Counties

Make selection: **Age group** All ages

Percentage ever diagnosed with asthma among residents of all ages, by county (2019–2020)

County	% of County Population
Alpine	25.1%
Amador	25.1%
Calaveras	25.1%
Inyo	25.1%
Mariposa	25.1%
Mono	25.1%
Tuolumne	25.1%
Yolo	24.7%
Solano	22.3%
Napa	22.0%
Kings	21.2%
Shasta	20.5%
Butte	20.2%
Fresno	20.0%
Marin	19.6%
Madera	19.4%
Lake	19.0%
Merced	18.9%
Colusa	18.6%
Glenn	18.6%
Tehama	18.6%
Contra Costa	17.9%
Kern	17.7%
Placer	17.7%
Sonoma	17.7%
El Dorado	17.4%
San Mateo	17.1%
Stanislaus	17.0%
Humboldt	16.8%
Sutter	16.7%
San Benito	16.4%
Sacramento	16.0%
San Joaquin	15.9%





Bars are missing on chart and values are marked as "Not available" when not enough data are available to calculate prevalence.

Certain counties with small populations are grouped together for analysis of prevalence data:
- Alpine, Amador, Calaveras, Inyo, Mariposa, Mono, and Tuolumne counties are combined
- Colusa, Glenn, and Tehama counties are combined
- Del Norte, Lassen, Modoc, Plumas, Sierra, Siskiyou, and Trinity counties are combined

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Equitable low-carbon transition pathways for California's oil extraction

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Check for updates

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Oil supply-side policies—setbacks, excise taxes and carbon taxes—are increasingly considered for decarbonizing the transportation sector. Understanding not only how such policies reduce oil extraction and greenhouse gas (GHG) emissions but also which communities receive the resulting health benefits and labour-market impacts is crucial for designing effective and equitable decarbonization pathways. Here we combine an empirical field-level oil-production model, an air pollution model and an employment model to characterize spatially explicit 2020–2045 decarbonization scenarios from various policies applied to California, a major oil producer with ambitious decarbonization goals. We find setbacks generate the largest avoided mortality benefits from reduced air pollution and the largest lost worker compensation, followed by excise and carbon taxes. Setbacks also yield the highest share of health benefits and the lowest share of lost worker compensation borne by disadvantaged communities. However, currently proposed setbacks may fail to meet California's GHG targets, requiring either longer setbacks or additional supply-side policies.

Across many industrialized economies, climate policies are increasingly focused on the transportation sector, which lags behind the level and pace of decarbonization observed in other sectors. Indeed, between 2010 and 2019, while non-transportation greenhouse gas (GHG) emissions have fallen by 6% across Organisation for Economic Co-operation and Development countries, GHG emissions from transportation have risen by 6% (ref. 1). Today, the transportation sector is responsible for the largest share of GHG emissions in the United States and the European Union at 28% and 24%, respectively, and an even larger share in California (40%), the region of focus in this study[1,2].

To date, transportation climate-policy debates have primarily focused on demand-side policies to reduce fossil fuel consumption, such as fuel taxes, vehicle fuel-economy standards, low-carbon fuel standards and electric vehicle subsidies[3–9]. In recent years, attention has turned towards supply-side policies that directly reduce fossil fuel production. These policies can take different forms. Some directly ban extraction from specific oil fields, such as oil-well setbacks targeted at

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fields located near where people live and work. Other policies reduce extraction by targeting oil fields according to their extraction costs, either on a per barrel basis as with an excise (or severance) tax or on a per GHG-emissions basis as with a carbon tax. Thus, for the same overall GHG emissions target, different supply-side policies can generate distinct aggregate and distributional consequences by reducing production from different oil fields.

Two primary considerations arise when evaluating supply-side policies. The first is the relative effectiveness of each policy type in reducing oil production and associated GHG emissions, which to date, has received limited empirical analysis[10–12]. The second pertains to the ancillary benefits and costs of each policy and how they are distributed across different communities. In particular, oil extraction tends to be highly spatially concentrated in certain areas, employing a local workforce and generating air pollution impacting nearby residents. Depending on how oil extraction is spatially located in relation to workers and households, different supply-side policies can have different aggregate and distributional consequences in terms of health benefits and labour-market impacts. For example, for the same overall GHG emissions target, a policy that phases out more labour-intensive oil fields may have higher lost worker compensation than other policies. Likewise, a policy that bans oil fields near where disadvantaged households reside may generate larger overall health benefits and health equity gains. Quantifying such potential consequences is critical for informing the design of supply-side policies. More broadly, there is a need to understand if and how effectiveness in GHG emissions reductions and distributional consequences trade off across different oil supply-side policies.

Previous decarbonization studies employ either Integrated Assessment Models, which are combined energy, economy and climate models[13,14], or macro energy-system models[15–17] that model regional energy systems. These models typically simulate or optimize energy infrastructure investments and retirements to meet certain GHG emissions-reduction targets by assuming that fossil fuel extraction will be phased out and replaced by cleaner alternatives. Such models typically do not explicitly consider how specific supply-side policies (other than a carbon tax) can yield different decarbonization outcomes for fossil fuel extraction. Furthermore, most energy or economic models lack the fine spatial resolution needed to examine the distributional outcomes of alternative policies over time. For example, existing studies on the distributional and equity consequences of phasing fossil fuel production including oil extraction use only the petroleum basin or county level and not the oil-field and census-tract-level representation for fuel production and air pollution exposure, respectively[15,18], which is critical to accurately estimate energy production, health effects and equity outcomes of decarbonization pathways.

This paper examines the effectiveness and distributional consequences of potential supply-side policies intended to phase out oil extraction across California. As the world's fifth-largest economy and the United States' seventh-largest oil-producing state, California provides a unique setting to study supply-side policies. The state is currently implementing some of the world's most ambitious climate policies with a statewide carbon-neutrality goal by 2045. This includes an active debate over various supply-side policies to dramatically reduce oil extraction, with an explicit interest in examining resulting labour and health equity consequences and their distribution across the state[19–21].We improve upon previous studies by developing an empirically estimated model of crude oil-well entry (drilling), production and exit (retirement) at the oil-field level along with an air pollution model to quantify health effects at the census-tract level and an employment input–output model to determine employment impacts at the county level. We examine three supply-side policy interventions that have been widely debated in California and elsewhere: (1) well setbacks that require new oil wells to be located beyond a specified minimum distance from sensitive sites such as occupied dwellings, schools, healthcare facilities and playgrounds; (2) an excise tax on each barrel of crude oil extracted and (3) a carbon tax on GHG emissions from oil extraction. We find that a setback policy provides greater statewide health benefits but also larger lost worker compensation compared with a carbon or excise tax that achieves the same 2045 GHG emissions target. In general, setback policies also have better equity outcomes as disadvantaged communities accrue a larger share of health benefits and a smaller share of loss in worker compensation. By contrast, a carbon tax imposes the smallest statewide worker compensation loss among the three policies. Finally, currently proposed setback distances applied to only new wells will be unable to meet California's decarbonization goals. To do so requires setbacks with a distance greater than 1 mile, applied to both new and existing wells and/or combined with a carbon or excise tax.

Crude oil production and GHG emissions pathways

We develop spatially and temporally explicit pathways that reduce California's oil extraction in response to various supply-side interventions—well setbacks, excise tax and carbon tax—between 2020 and 2045. Our approach has two components and is summarized in Fig. 1. For all oil fields in California (Fig. 1a), we first construct an empirically estimated model of crude oil-well entry (Fig. 1b), production and exit at the oil-field level to project how various supply-side policies and macroeconomic conditions affect oil production across California oil fields out to 2045 (Methods and Supplementary Notes 8–11, 16 and 17). In our second step, we insert field-level predictions of oil production from our empirical model into: (1) an air pollution model, InMAP (Intervention Model for Air Pollution)[22], to characterize how air pollution emissions from oil fields disperse across the state (Fig. 1c,d and Supplementary Note 13) and (2) an employment input–output model, IMPLAN (Impact Analysis for Planning)[23,24], which uses fixed multipliers to quantify local employment changes in the oil-extraction sector ('direct'), in sectors that provide inputs to oil extraction ('indirect') and in sectors where these workers spend income ('induced') (Fig. 1e and Supplementary Note 14). Together, these components provide an empirically based analysis of how supply-side policies could alter not just oil production across oil fields but also the spatial distribution of health impacts from air pollution and employment across California.

For well setbacks, we consider three setback distances—1,000 feet, 2,500 feet and 1 mile—which encompass distances currently considered in policy proposals[25–28]. To ensure policy comparability, we set excise taxes as a percentage of oil price fixed across all years and carbon taxes which increase at an annual rate of 7% to levels that result in the same 2045 statewide GHG emissions as our three setback-distance policies (Supplementary Note 17). We further consider a fourth excise- and carbon-tax level that achieves a 90% GHG emissions reduction by 2045 compared with 2019 levels, inline with California's target for in-state finished-fuel demand[2].

Each combination of policy intervention—setbacks, excise tax and carbon tax—and the 2045 annual GHG emissions target result in a unique spatial and temporal pattern of oil production, benefits and costs. We model these patterns across California for the 2020–2045 period, focusing on avoided mortality due to reduced $PM_{2.5}$ emissions and avoided global climate damages from reduced GHG emissions on the benefits side and lost earnings from the oil-extraction sector on the cost side. We analyse these policy scenarios using a common benchmark projection of global oil prices out to 2045 (US Energy Information Administration's (EIA) reference oil-price projection[29]). Sensitivity analysis results using higher and lower projected oil prices are shown in the Supplementary Information.

California's oil production peaked in 1985 and has been declining since then[30]. Our projection of statewide oil production to 2045 under a business-as-usual (BAU) scenario continues this trend (Fig. 2). In this no-supply-side policy BAU scenario, oil production in 2045 decreases

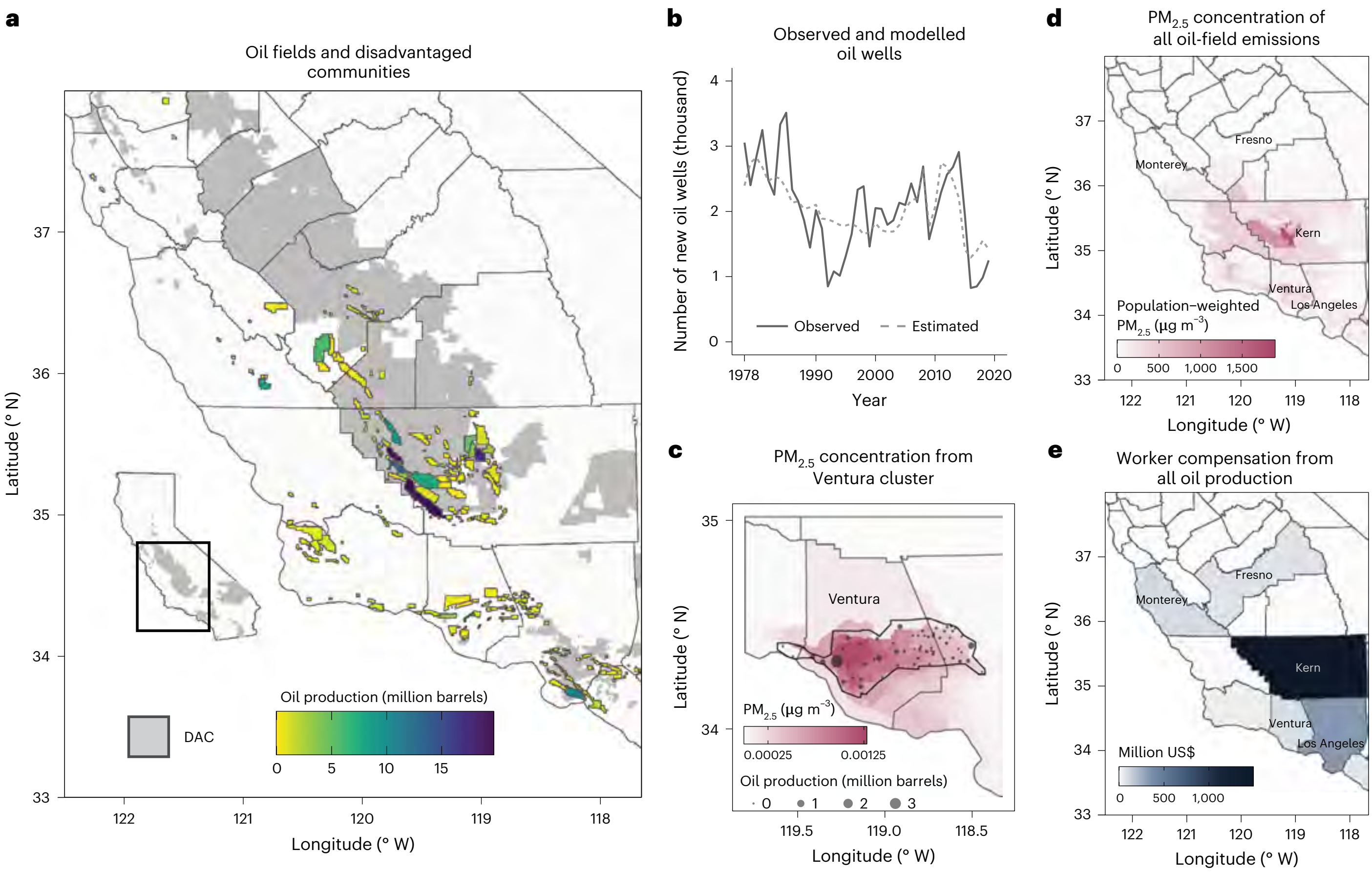

Fig. 1 | Summary of data and methods. a, Oil production in 2019 by field. Grey shaded areas indicate census tracts with disadvantaged communities (DAC), as defined by CalEnviroScreen. **b**, Observed and estimated historical oil-well entry across California (Supplementary Note 9). **c**, Particulate matter ($PM_{2.5}$) concentration by census tract for a 1 tonne pulse of $PM_{2.5}$ emissions from the Ventura cluster. Points indicate location of 2019 oil production from oil fields within the cluster. **d**, $PM_{2.5}$ concentration by census tract associated with all 2019 oil production. **e**, Worker compensation by county associated with all 2019 oil production.

by 57% compared with 2019 levels. Associated GHG emissions decline by 53%, which is well short of California's decarbonization targets.

Supply-side policies lower statewide crude oil production but with different temporal and spatial patterns (Fig. 2a and Supplementary Fig. 17). Setbacks applied to new wells, excise taxes applied per unit of production and carbon taxes applied per tonne of GHG emissions lead to continuous declines that outpace that of the BAU trajectory, albeit with different pathways. In general, a setback and an excise tax result in lower oil production in each year when compared with a carbon tax that is calibrated to achieve the same 2045 GHG emissions target. This is because a carbon tax on extraction emissions targets oil fields with higher GHG emissions intensities, whereas a setback targets oil fields in more populated areas and an excise tax targets production declines among more costly oil fields. Supplementary Fig. 1 shows that the relationship between production costs and emissions intensities is not systematic. As a result, the fields that reduce production under a carbon tax will be unique from the fields that reduce production under an excise tax that achieves an equivalent reduction in carbon emissions.

There is close correspondence between statewide oil production and emissions pathways (Fig. 2b). As with oil production, setbacks, excise taxes and carbon taxes induce a continuous decline. By construction, because excise- and carbon-tax levels were calibrated to result in the same 2045 GHG emissions as the corresponding setback distances, the GHG emissions trajectories of setbacks, excise taxes and carbon taxes are more closely aligned than oil-production trajectories. Cumulative 2020–2045 GHG emissions reductions from carbon taxes are consistently lower than setbacks and excise taxes for each 2045 GHG emissions target, irrespective of the oil-price projections (Fig. 2c and Supplementary Figs. 24 and 25). However, excise taxes, depending on the tax level required to meet the GHG emissions target under different oil prices, could have slightly lower or higher cumulative GHG emissions compared to setbacks. When considering alternative oil-price projections, annual GHG emissions reduction in 2045 for a 1 mile setback is substantially lower (33%) under EIA's high oil-price projection (Supplementary Fig. 24), while it nearly reaches the 90% reduction target under EIA's low oil-price projection (89% reduction) (Supplementary Fig. 25).

Health, labour and avoided climate change impacts

Reduced crude oil production from supply-side policies have associated health benefits, labour-market impacts and benefits from avoided climate change damages. We estimate statewide health benefits from cumulative avoided mortality resulting from lower air pollution levels, costs from lost total labour compensation and benefits from avoided climate change damages due to abated GHGs, priced at the social cost of carbon[31], both total (Fig. 3a–c) and per unit of cumulative avoided GHG emissions over 2020–2045 for each scenario (Fig. 3d–f). The costs and benefits are relative to the BAU scenario and estimated in net-present-value terms, valued in 2019 US dollars (Supplementary Notes 13–15).

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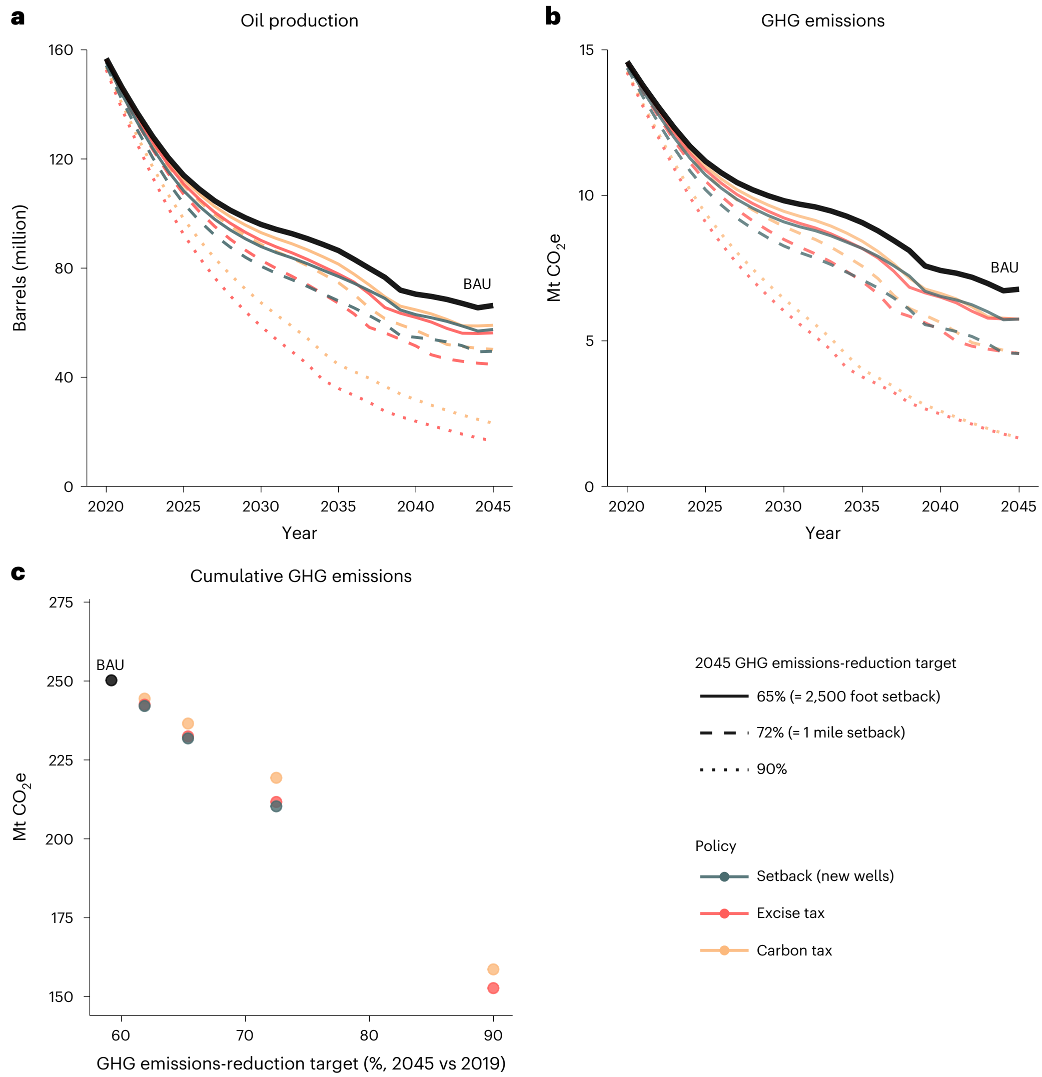

Fig. 2 | California crude oil production and associated GHG emissions pathways. Annual California oil production and GHG emissions under BAU and three supply-side policies—setbacks applied to new wells, excise tax on oil production and carbon tax on emissions from oil extraction. Excise and carbon taxes are calibrated to meet 62% (= 1,000 foot setback), 65% (= 2,500 foot setback), 72% (= 1 mile setback) and 90% GHG emissions reduction by 2045 relative to 2020. **a**, Crude oil production. **b**, GHG emissions from crude oil production. **c**, Cumulative 2020–2045 GHG emissions. Data for 62% GHG emissions-reduction scenario (= 1,000 foot setback) not shown in **a** and **b** for visual clarity. Setback distances are limited to 1 mile or below, and thus, a setback that meets a 90% 2045 GHG emissions target is not modelled. Total number of oil fields in the model is 263. CO_2e = carbon dioxide equivalent.

We note that health benefits denominated in monetized avoided mortality from air-quality improvements and lost worker compensation from oil extraction reported here do not provide a full account of statewide benefits and costs under each supply-side policy. Reductions in ambient air pollution can bring a wide range of health benefits, including reduced morbidity, asthma attacks and other respiratory diseases and lower hospital and medication expenses. For example, reduced activity in the oil and gas extraction sectors may reduce ground-level ozone concentrations, which may lead to additional health benefits that are not accounted for in our study[32]. To the extent that other ambient air pollutants such as ozone travel similarly to $PM_{2.5}$, the disadvantaged communities vs non-disadvantaged communities contrasted in the estimated health benefits should be a reasonable approximation of the full health benefits comparison despite focusing only on primary and secondary $PM_{2.5}$.

We focus on monetized avoided mortality alone to measure the benefits of air-quality improvements because the previous literature has shown that monetized avoided mortality is by far the largest benefit[33]. Premature mortality is also the health end point for which there is the most scientific consensus supporting the causal link between air pollution (in particular $PM_{2.5}$) and the end point[33]. There are also potential benefits associated with non-health impacts through changes in agricultural and labour productivity[34,35]. Likewise, we are unable to account for the possible re-employment of oil-extraction workers that may find employment in other sectors. Unfortunately, little is known on re-employment rates and wages for former oil-extraction workers to inform such calculations. Thus, our estimates represent lower bounds of potential health benefits and upper bounds of potential employment and worker compensation losses. Lastly, considerable uncertainty exists in the value of the social cost of carbon, a key ingredient in how avoided climate damages are calculated[31]. For these reasons, we present our health, labour and avoided climate damage values separately in Fig. 3, without attempting to conduct a full cost–benefit analysis. We instead focus on the relative rankings of each benefit and cost across the three supply-side policies examined.

Among policies, setbacks consistently achieve the greatest health benefits, both in total and per unit of cumulative avoided GHG emissions (Fig. 3a,d). This result validates the intent behind setbacks, a

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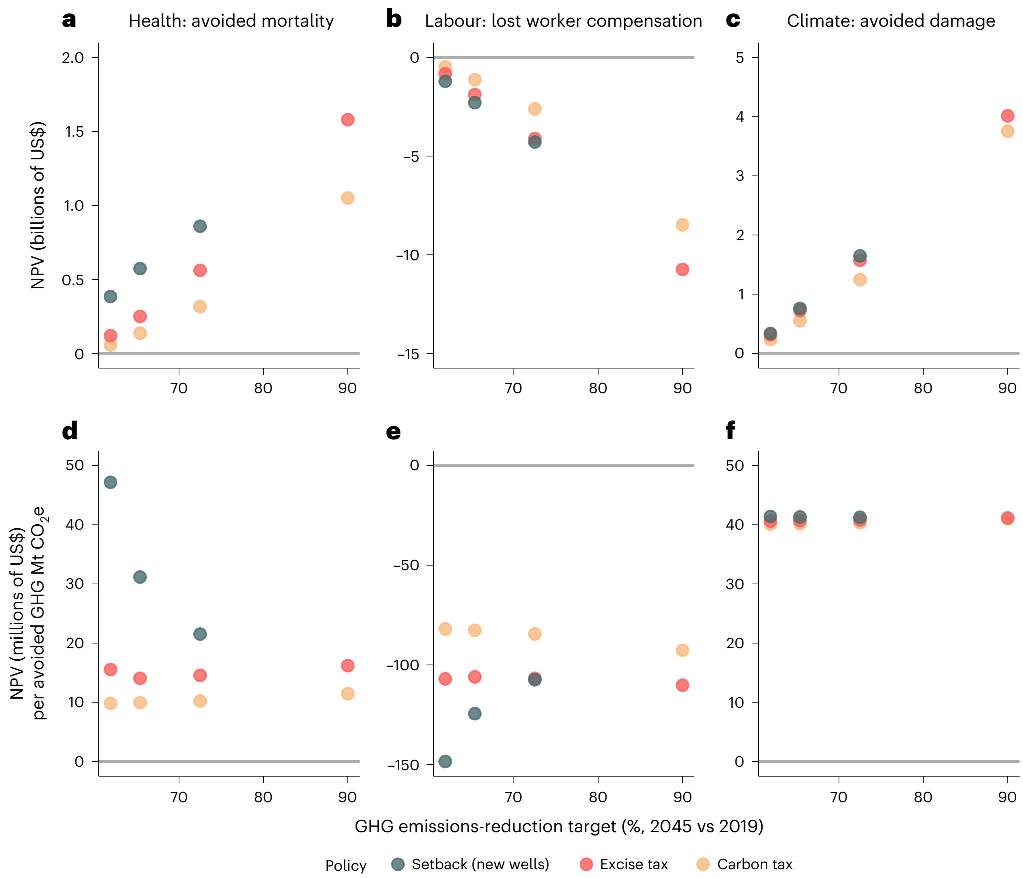

Fig. 3 | Health, labour and climate impacts from California's oil-production pathways under different policies relative to BAU. a–**c**, Total health benefits from avoided mortality (**a**), total lost worker compensation (**b**) and avoided climate damages valued at the social cost of carbon over 2020–2045 (**c**) under three supply-side policies—setbacks applied to new wells, excise tax on oil production and carbon tax on emissions from oil extraction—relative to BAU to meet four 2045 GHG emissions targets. **d**–**f**, Panels replicate **a** (**d**), **b** (**e**) and **c** (**f**) but normalized by cumulative avoided GHG emissions over 2020–2045. No setback distance equivalent to 90% 2045 GHG emissions target is applied. Total number of oil fields in the model is 263. Net present values (NPV) are in 2019 US dollars, estimated using a discount rate of 3%.

policy designed specifically for improving health outcomes by eliminating oil extraction from fields that are situated near residences, schools and other locations where people live and work. However, per unit of cumulative avoided GHG emissions, longer-distance setbacks yield smaller health benefits (Fig. 3d) because the marginal pollution from avoided wells affects a smaller number of people.

For statewide worker compensation losses, the pattern flips across supply-side policies. For a given 2045 GHG emissions target, setbacks consistently generate slightly higher worker compensation losses across the state than excise taxes, which exceed that for carbon taxes (Fig. 3b). This is because setbacks experience a drop in production larger than excise and carbon taxes designed to meet the same 2045 GHG emissions target, and they affect wells in counties that have a higher employment intensity (jobs per barrel of oil produced). Excise taxes lead to greater worker compensation loss because they are less cost effective at targeting GHG emissions reductions compared with carbon taxes, requiring a larger drop in oil production and associated employment losses to meet the same GHG emissions target. The ranking across policies is preserved when considering worker compensation losses per unit of cumulative avoided GHG emissions (Fig. 3e).

For avoided climate change damages, setbacks deliver slightly greater cumulative benefits for each 2045 GHG emissions target compared with excise and carbon taxes (Fig. 3c). These differences are even smaller across policies on a per unit of cumulative avoided GHG emissions basis (Fig. 3f).

The relative ranking for the health impacts from the three supply-side policies remains the same under the EIA's high and low oil-price projections, although the average magnitude of these benefits and costs are correspondingly higher or lower than the reference EIA oil-price projection (Supplementary Figs. 26 and 27). Cumulative lost worker compensation and avoided climate damages remain the lowest for carbon taxes across high and low oil-price projections (Supplementary Figs. 26 and 27).

Drivers of health and labour outcomes across policies

The ranking of health benefits and labour costs shown in Fig. 3 across supply-side policies occurs because each policy targets different aspects of crude oil production and thus the sequence and timing of well entry, production and retirements across oil fields. To explore this further, we sort oil fields according to the characteristic directly targeted by each policy. Specifically, these characteristics, shown on the x axis across the columns of Fig. 4, include an oil-field cluster's: (1) area share near sensitive sites, (2) per barrel cost of extraction per barrel and (3) GHG emissions intensity per barrel. These characteristics are directly affected by a setback, an excise tax and a carbon tax. Under each policy, oil fields on the left of the x axis retire first, moving rightward as stringency tightens. For example, for a particular setback distance (2,500 feet in Fig. 4a,d), fields with a greater share of their area near sensitive sites will experience greater reduction in oil production than fields with areas less affected by the same setback. The latter fields that

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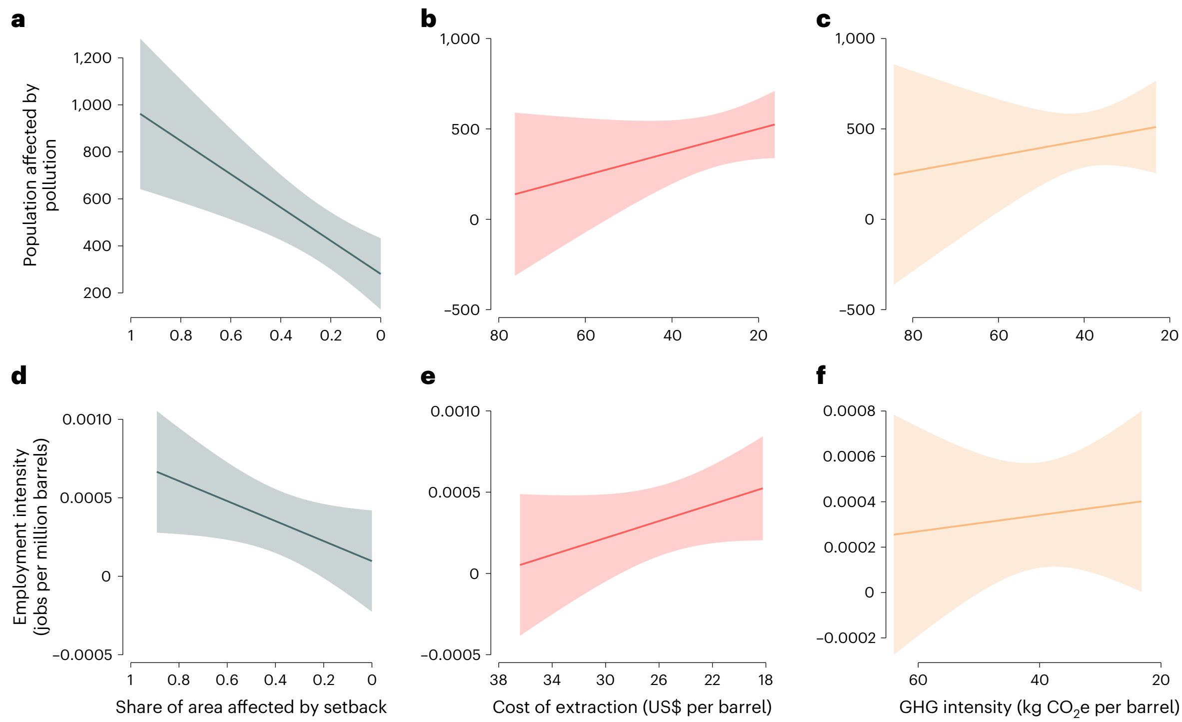

Fig. 4 | Correlations between health and labour impacts with oil-field characteristics. a–c, Correlation between statewide population affected by a 1 tonne pulse of $PM_{2.5}$ from an oil-field cluster on the *y* axis and that cluster's share of area affected by setback (at 2,500 feet) in blue (**a**); cost of extraction (in US dollars per barrel) in red (**b**); and GHG intensity (in kg CO_2e per barrel) in orange (**c**) on *x* axes. **d–f**, Replicates **a–c** but with employment intensity (in jobs per million barrels of oil produced) on the *y* axis at the county level. Total number of oil fields in the model is 263. All oil-field characteristics shown here are estimates from 2020. Data are presented as mean values ± 1.96 × standard errors of measurement (SEM).

are farther from sensitive sites will be increasingly affected as setback distances increase. Likewise, under a low excise tax, the oil fields that initially phase out production are those with higher extraction costs. As the excise tax increases, oil fields with lower extraction costs incrementally phase out production. A similar pattern holds for carbon taxes and their effect on oil fields with varying GHG intensities.

To understand how policies differ in terms of statewide health benefits, the *y* axis in the top panels of Fig. 3 shows the number of affected individuals per unit of pollution for each oil field. Because of the downward relationship shown in Fig. 4a, shorter distance setbacks initially affect oil fields that are upwind of more population-dense locations. As setback distances increase, the marginal oil field that is phased out is upwind of fewer people, explaining why the health benefit per unit of cumulative avoided GHG emissions falls with more stringent setbacks (Fig. 3d). By contrast, the relationships between population affected by pollution and costs of extraction and GHG intensity of oil fields are both upward sloping (Fig. 4b,c). This is reflected in the increasing health benefits, in both total and per unit of cumulative avoided GHG emissions, with increasing stringency of excise and carbon taxes (Fig. 4a,d). In other words, as excise and carbon taxes increase, the marginal oil field that exits production is upwind of more people.

To understand patterns in labour-market impacts, we explore correlations between employment intensity in the oil-extraction sector at the county level in total job losses per million barrels of oil produced and the three oil-field characteristics (Fig. 4d–f). The employment impacts reported in this study are driven by IMPLAN multipliers that account for direct, indirect and induced jobs. As shown in Fig. 4, oil fields that are more impacted by setbacks have a greater employment intensity (jobs per million barrels), reflecting larger multipliers and county population. For example, oil fields in Los Angeles County are affected more by shorter setbacks because a larger population in the county lives close to oil fields, but they also create more direct, indirect and induced jobs based on IMPLAN's data. The downward relationship in Fig. 4d explains why employment loss per GHG emissions reduction is the highest at shorter setback distances (Fig. 3d). Shorter setbacks induce more labour-intensive oil fields to exit production first, followed by less labour-intensive fields as setback distances increase. Again, by contrast, Fig. 4e,f is upward sloping, indicating that with excise and carbon taxes, less labour-intensive oil fields go out of production first. This is consistent with statewide labour costs, in both the total and per unit of cumulative avoided GHG emissions basis, increasing (more negative) in Fig. 4b,e as excise- and carbon-tax stringency increases. Higher excise and carbon taxes incrementally induce more labour-intensive fields to go out of production.

County-level outcomes are similarly driven by county and oil-field characteristics. Comparing California's three highest oil-producing counties in 2019, production in Los Angeles County has lower average costs per barrel and lower average GHG emissions intensity compared with Kern or Monterey counties (Supplementary Figs. 19 and 20) but greater health impacts (mortality) and employment intensity per barrel of oil production (Supplementary Figs. 21–23). Under a setback policy, oil production in denser Los Angeles County is affected more than Kern and Monterey counties (Supplementary Fig. 18), which results in greater health benefits but also higher labour impacts compared with the excise- and carbon-tax policies. Because the average cost of oil production and GHG emissions intensities in oil fields in Kern and Monterey counties are greater than Los Angeles County, both the excise- and carbon-tax policies result in lower health benefits and labour impacts compared to the setback policy.

Equity impacts of supply-side policies

To understand the equity impacts of supply-side policies, we examine how the statewide health and labour consequences of each decarbonization pathway are distributed spatially across the state. We use

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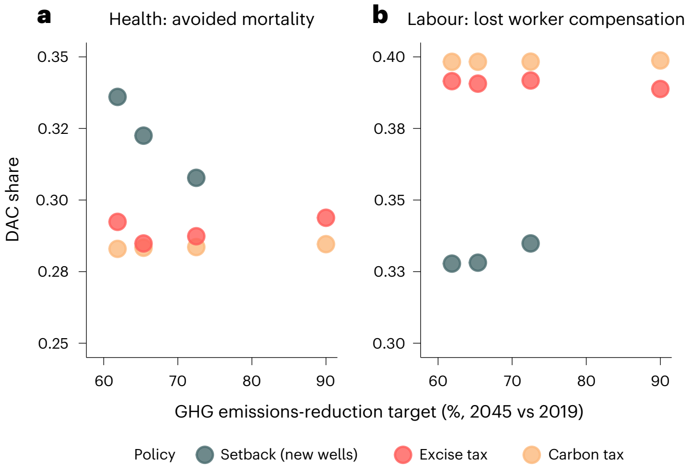

Fig. 5 | DACs' share of health and labour impacts. a,**b**, Share of avoided mortality benefits borne by individuals (**a**) and share of foregone oil-extraction earnings borne by workers in DACs (**b**) under setbacks, excise tax and carbon tax for different 2045 GHG-reduction targets.

California's legal definition of whether a census tract is a 'disadvantaged' community (DAC) using CalEnviroScreen, a scoring system based on multiple-pollution exposure and socioeconomic indicators developed by the California Environmental Protection Agency[36]. For each policy scenario, we estimate the share of the total statewide health benefits and employment losses in oil extraction borne by communities living in disadvantaged community census tracts (Fig. 5a,b).

The DAC's share of health benefits is consistently larger under a setback than under excise and carbon taxes for a given 2045 GHG emissions target. This share is largest at lower setback distances or equivalently less stringent 2045 GHG emissions targets and decreases as the setback distance increases. For excise and carbon taxes, the DAC's share of benefits is relatively unaffected by the stringency of the 2045 GHG emissions target. The lost worker compensation is largest for setbacks at the statewide level. However, the share of total lost worker compensation from workers in DACs is consistently lower under setbacks than under excise and carbon taxes. Thus, for any given 2045 GHG emissions target, a greater share of health benefits and a lower share of worker compensation impacts are experienced by DACs under a setback than under excise and carbon taxes. This result holds even under the EIA's high and low oil-price projections (Supplementary Figs. 28 and 29).

Setbacks applied to all versus only new wells

Although most existing and proposed setback policies apply to only new wells, applying setbacks additionally to existing wells could be an important policy instrument to further mitigate GHG emissions and improve health outcomes of neighbouring communities that have historically borne the burden of local pollution from oil extraction. To understand the health, labour and equity consequences of setbacks on all wells, we also model a setback policy that affects both new and existing wells applied in 2020.

In comparison to setbacks on only new wells, applying setbacks to all wells predictably results in greater oil-production declines and emissions reductions. As discussed earlier, setbacks applied to only new wells result in a continuous decline in oil production and GHG emissions (Fig. 6). In contrast, setbacks applied to all wells induce an immediate drop in statewide oil production and associated GHG emissions in 2020 as existing wells within the setback distance fall out of production. This drop is then followed by a gradual decline thereafter that tracks the BAU trajectory. Oil production and GHG emissions reductions increase as setbacks get longer. Although a 1-mile setback, the largest considered in this study, applied to all wells achieves a substantially greater GHG emissions reduction (81%) by 2045 compared with the same setback on new wells (72%), it still falls short of meeting the 90% reduction target (Fig. 6b). However, the cumulative GHG emissions reduction over 2020–2045 for the 1-mile setback applied to all wells is on par with those of excise and carbon taxes that result in a 90% annual GHG emissions reduction in 2045 (Fig. 2c).

Setbacks applied to all wells result in fewer premature deaths but also greater total lost worker compensation compared with setbacks on only new wells (Fig. 6). Setbacks on all wells have better equity outcomes by accruing a greater share of avoided mortality benefits and a lower share of lost worker compensation to disadvantaged communities. Thus, setbacks applied to all wells in general would yield more pronounced health and labour-market consequences than setbacks applied to just new wells.

Discussion and conclusions

By quantifying the trade-offs across different supply-side policies, we find that for California, an oil-well-setback policy applied to new wells provides greater health benefits compared to a carbon- or excise-tax policy designed to achieve the same 2045 GHG emissions-reduction target. A setback policy also produces equity gains as DACs accrue greater health benefits and lower employment costs than other communities under a setback compared to excise and carbon taxes.

Yet a setback policy imposes the largest statewide loss of worker compensation among the three policies for the reference oil-price projection. Moreover, on its own, a setback policy applied to new wells achieves only a 72% GHG emissions reduction in 2045 compared with 2019 for a 1-mile setback, a distance larger than the maximum 3,200 feet currently proposed in California[28]. GHG emissions reductions would be even lower under higher global crude oil prices. While a setback policy is generally advocated by stakeholders based on public health concerns, it will need to either impose greater distances, be applied to both new and existing wells or be combined with an appropriate excise or carbon tax to meet California's decarbonization goals (Supplementary Figs. 30–35).

Whereas carbon taxes and excise taxes are both able to achieve more aggressive annual GHG emissions reductions, that is, 90% GHG emissions reduction by 2045 compared with 2019, the tax values required to achieve 90% decarbonization are higher than those considered in current policies. The carbon tax required to drive a 90% GHG emissions reduction by 2045 starts at US\$250 t^{-1} CO_2e in 2020 and increases to US\$1,330 t^{-1} CO_2e in 2045. This trajectory is nearly four times higher than the allowance price ceiling under California's cap-and-trade system that starts at US\$65 t^{-1} CO_2e in 2021 and rises to US\$330 t^{-1} CO_2e by 2045, assuming an annual real growth rate of 5% and an inflation rate of 2% (ref. 37). Similarly, none of the excise taxes currently in effect across 27 US states exceed 10% of the oil price[38], which is far lower than the 67% tax we find is required to achieve a 90% GHG emissions-reduction target by 2045 under EIA's reference oil-price projection.

Finally, our results indicate that combining a setback with a carbon tax could achieve the state's GHG emissions target while yielding greater statewide health benefits, lower statewide worker compensation losses and larger equity gains compared to having just a carbon tax or excise tax alone. However, if the setbacks are applied to only new wells, the carbon-tax trajectory would still need to be three times higher than currently permitted under California's cap-and-trade system (Supplementary Fig. 16). For the two trajectories to be similar, setbacks would need to be applied to both existing and new wells.

Although we examined only the impacts of $PM_{2.5}$ on health outcomes, oil extraction also emits other toxic pollutants, including benzene, ethylbenzene and *n*-hexane, which are known to cause cancer and other serious health effects[39]. Setbacks will not only reduce exposure to $PM_{2.5}$ pollution but will also decrease exposure to these other toxic pollutants and thus could lead to larger health benefits as oil extraction is phased out. To realize the health and climate benefits of setbacks

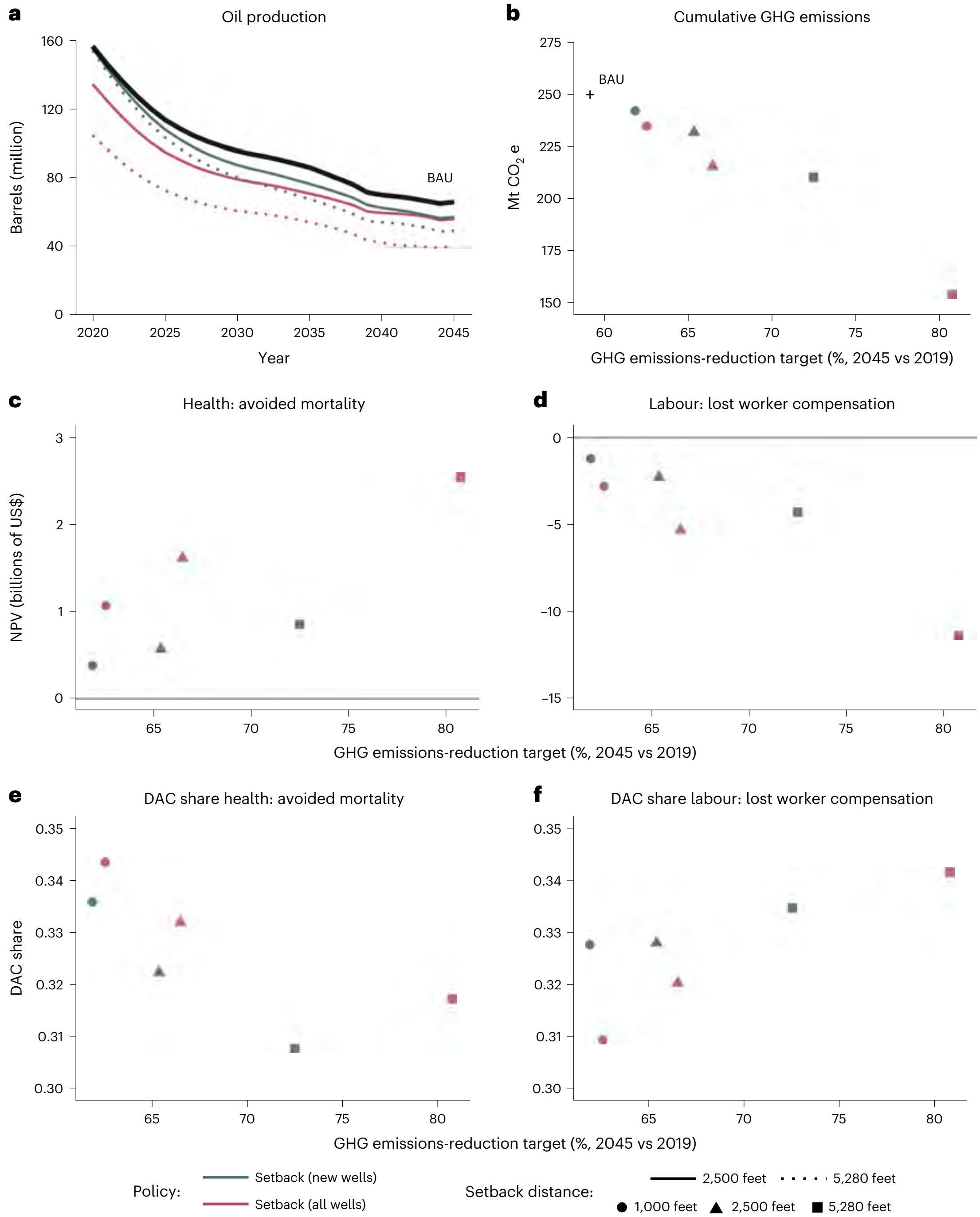

Fig. 6 | Comparison between setback policies applied to new and all wells. **a**–**f**, Three setback distances—1,000-foot setback, 2,500-foot setback and 1-mile setback—applied to new and all (new and existing) wells. Oil-production pathways (**a**), cumulative GHG emissions over 2020–2045 (**b**), total health benefits from avoided mortality (**c**), total lost worker compensation (**d**), share of avoided mortality benefits borne by individuals in DACs (**e**) and share of foregone oil-extraction earnings borne by workers in DACs (**f**) under the three setbacks. Total number of oil fields in the model is 263. Net present values are in 2019 US dollars, estimated using a discount rate of 3%.

estimated in this study, setbacks will need to be applied to both existing and new wells, unlike most existing and proposed regulations that apply setbacks to only new wells.

Two other supply-side policies that we do not examine in this study include limiting producer subsidies[14,40] and restricting development of oil fields, either by compensating resource owners for not exploiting their fuel resources, buying and retiring resource rights or limiting new leases on government lands[10,41]. The former is similar to imposing an excise tax on production, whereas the latter requires rules to prioritize fields for constraining development, similar to a setback policy that is considered in this study.

The effectiveness and equity trade-offs across various oil supply-side policies must be ultimately considered in tandem with oil demand-side policies, without which global GHG emissions reductions may be limited when oil markets are global. For example, demand-side policies from any jurisdiction alone may yield limited GHG emissions reductions if other jurisdictions increase oil demand in response to lower global oil prices[11,42,43]. Similarly, restricting only oil supply in a single jurisdiction without efforts to limit oil demand in that jurisdiction will result in an increase in oil exports from elsewhere, with some amount of local GHG emissions reduction replaced by increased GHG emissions elsewhere. By coordinating oil supply- and demand-side policies, it is possible for a jurisdiction's oil supply and demand curves to jointly shift in a manner that leaves the global oil price unchanged and avoid GHG leakage to other jurisdictions.

Additionally, demand and supply policies that simply reduce GHG emissions from transportation fuels may have limited GHG emissions reductions if there is not an economy-wide climate policy, such as a carbon price, that ensures any energy source that replaces oil for transportation, such as electricity, is not more carbon intensive. For example, a transition from oil to electricity in transportation may have limited climate benefits if the electricity is produced primarily by coal. Future research should assess the resulting effectiveness and equity consequences of having multiple complementary climate policies.

Such future analyses can take advantage of the methodological approach developed in this paper. Across many settings and sectors, stakeholders are asking decarbonization policies to take into account not just their GHG emissions consequences but also how the local costs and benefits of these policies are distributed spatially and across different demographic groups. This paper provides a step forward in that direction by combining an empirical-based, spatially explicit energy production model with state-of-the-art air pollution transport modelling to quantify health benefits at a fine spatial scale and an employment model to quantify local labour-market consequences. Our framework can be applied to other decarbonization policies at various scales such as studying the distributional consequences of decarbonizing other forms of fossil fuel extraction, electricity production or manufacturing activity. More broadly, in many settings that already exhibit socioeconomic inequities, there is an increasing need to understand whether decarbonization policies themselves would exacerbate or narrow such inequities. This study and its methodology provides a path forward for such analyses.

Methods

Modelling framework

To estimate the health and labour consequences of supply-side policies, we build an empirically validated model of oil production to estimate field-level oil production and GHG emissions pathways under varying policy scenarios. These estimates drive our projections of pollution dispersion, mortality effects and local employment, which are used to quantify health and labour impacts under different policy and GHG emissions-target scenarios. We further examine the equity impacts of these scenarios focusing on how health and labour impacts are distributed between disadvantaged and other communities. Throughout, we use nominal prices in both the estimation and projection parts of the analysis. When presenting health and labour impacts, we calculate net present discounted values in 2019 US dollars after applying a discount rate of 3% and an inflation rate of 2%.

Supply-side policies and oil-price forecasts

We model the impacts of three policies—setbacks, an excise tax and a carbon tax—on California's oil sector. A setback policy prohibits oil (and gas) extraction within a specified distance from sensitive sites including occupied dwellings, schools, healthcare facilities and playgrounds. We model two setback scenarios: (1) setbacks that apply to new wells only (main results) and (2) setbacks that apply to new and existing wells or all wells. We model setbacks on new wells by proportionally reducing field-level future new well entry based on the relative field area covered by a given setback buffer. For existing wells, setbacks are implemented in our model by removing those within the setback distance from future production. We consider setback distances of 1,000 feet, 2,500 feet and 1 mile. We assume only vertical drilling in the setback analysis. Horizontal and directional drilling from pads outside of the setback distance could access additional sub-surface oil resources within the setback distance, reducing our estimates of the health and equity benefits of setbacks, especially for shorter setback distances[44]. However, the costs and extent of adoption of horizontal drilling are uncertain for California and thus are not included in this study. The excise-tax policy imposes a tax on each barrel of crude oil extracted. In our projection period, we apply a constant tax rate to the oil price each year. This is consistent with historical proposals for excise taxes on California oil extraction[45]. The carbon-tax policy imposes a tax on the GHG emissions from the oil-extraction site. We consider only direct GHG emissions, excluding methane emissions due to a lack of reliable oil-field-specific data. All carbon-tax trajectories increase at an annual rate of 7%, the sum of a 5% real growth rate and 2% inflation rate per year (ref. 46). We determine the excise-tax rates applied to the oil price and carbon taxes that result in the following 2045 statewide GHG emissions targets using an optimization function: (1) 2045 statewide GHG emissions associated with the three setback distances (Supplementary Table 4) and (2) a 90% reduction in statewide GHG emissions compared with 2019. The excise and carbon taxes are shown in Supplementary Figs. 15 and 16 and are inputs to the oil-extraction model and affect future well entry and exit. Supplementary Note 17 provides more details.

For 2020–2045 macroeconomic conditions, we assume three Brent spot crude oil nominal price trajectories (reference, low and high) obtained from the EIA's Annual Energy Outlook 2021 forecast (Supplementary Fig. 13) (ref. 29). For scenarios that do not include a carbon tax, we apply a baseline nominal carbon price equal to California's cap-and-trade allowance price floor (Supplementary Fig. 14). Supplementary Note 16 provides more details.

Oil-production model

The model of oil production has three components: (1) well entry, (2) annual production after entry and (3) well exit.

We model new well entry by estimating a Poisson model of well entry using data on historical production from existing wells and fields, costs and crude oil nominal prices. Specifically, we estimate annual new well entry in an oil field as a function of oil prices, field-level capital and operational expenditures (Supplementary Figs. 2–4) and field-level depletion. Details are provided in Supplementary Note 9. This model is estimated using well-entry data between 1977 and 2019 from California's Department of Conservation's WellSTAR database[47]. Supplementary Notes 1 and 3–5 provide more information on the input data. Capital and operational expenditure data are from the subscription-based data provider Rystad Energy (Supplementary Note 2). Model estimates are provided in Supplementary Table 1.

After estimating the well-entry model, we predict annual well entries for the 2020–2045 projection period using forecasted nominal prices and prescribed policy conditions. Field-level operational costs are modified each year based on the relevant carbon and excise tax. The setback policy constrains projected new well entry in a given field by reducing the number of predicted new wells by the percentage of field area covered by a setback. Figure 1 and Supplementary Fig. 5 compare the predicted and observed entry at the state level and for each top field category, respectively.

To predict annual oil production after well entry, we estimate oil-production decline curves at the field and vintage level for both existing (that is, pre-2020 entry) and new wells (that is, wells that enter during 2020–2045). Production from oil wells often follow a declining profile of production until the wells exit[48,49]. For existing wells, we estimate the decline-curve parameters using historical oil-production data (Supplementary Note 10) and apply them to the decline-curve equations to estimate future annual production at the field-vintage level. To predict future production from new wells, we extrapolate historical parameters using a linear regression model to obtain values for the 2020–2045 forecast period. In each forecast year for each field, we use the corresponding extrapolated decline parameters and decline-curve equations to determine field-vintage-level production from the year the wells enter through the end of the projection period. We repeat this process for all forecast years. Modelled production decline curves and actual production for two fields are shown in Supplementary Figs. 6 and 7.

Because most wells that idle for a long time stop producing altogether[50], we use historical data on wells that idled continuously for ten years as a proxy for wells that stop producing and exit. We model well exits as a function of the nominal oil price, nominal field-level operational costs and field-level depletion. We estimate the parameters of the model using historical data from 1977 to 2019 and apply the parameters to predict future well exit in the period 2020–2045, again modifying field-level operational costs each year based on the relevant carbon and excise taxes. Supplementary Note 11 provides details. Model estimates are provided in Supplementary Table 1. Supplementary Figs. 8 and 9 compare the predicted and observed exit at the state level and for each top field category, respectively.

To account for well exits and setbacks, we adjust the predicted production from both existing and new vintages. We assume that each well in a given field-vintage produces the same amount of oil. Each year the exit model predicts the number of wells that exit from each field. We then remove these wells in order of vintage, starting with the oldest. For vintages that experience well exit, future production is correspondingly decreased to account for the reduction in number of wells in production. Similarly, for existing vintages we adjust predicted production to account for wells prohibited from future production due to setbacks by reducing production volumes proportionally by the number of wells removed by the setback. Supplementary Note 8 provides more details about the oil-production model.

GHG emissions

We estimate GHG emissions associated with oil extraction using field-specific GHG emissions factors. We first estimate historical GHG emissions factors using the Oil Production Greenhouse Gas Emission Estimator (OPGEE) model v2.0 from the California Air Resources Board[51,52] (Supplementary Fig. 10 provides 2015 data). The OPGEE model is an engineering-based life-cycle assessment tool for the measurement of GHG emissions from the production, processing and transport of crude oil. Using the OPGEE model and oil-extraction data from the California Department of Conservation, we model field-level GHG emissions for the years 2000, 2005, 2010, 2012, 2014, 2016 and 2018. We consider only upstream emissions from exploration, drilling, crude production, surface processing, maintenance operations, waste treatment/disposal and other small sources (as modelled by OPGEE). To obtain emissions factors for oil fields that were not modelled by OPGEE, we apply the median emissions factors for the fields that were modelled, separated by the use of steam injection (Supplementary Note 12 provides more information). To estimate the field-level GHG emissions for the projection period (2020–2045), we average the historical emissions factors for each year, again separated by fields based on the use of steam injection. We then linearly regress the average emissions factors and extrapolate over the projection period. Last, we apply the percent change in emissions factor between each forecast year to the field-level historical emissions factors from 2018 onwards to determine field-level emissions factors for each forecast year. Supplementary Note 12 provides more details.

Health impacts

We first estimate $PM_{2.5}$ emissions from oil production for each oil-field cluster (set of oil fields clustered by geographical proximity; Supplementary Fig. 11) using average emissions factors obtained from a nationwide US sample[53] (Supplementary Table 2). Using average $PM_{2.5}$ emissions factors is a limitation of the study due to the lack of field-specific $PM_{2.5}$ emissions factors. In practice, actual emissions factors are probably highly heterogeneous across oil fields. Emissions-factor heterogeneity can arise from differences across $PM_{2.5}$ emissions sources—which include on-site fossil fuel combustion from processing plants, generators, pumps, compressors and drilling rigs, flaring, gas venting, dust from heavy vehicles and secondary formation from ambient conditions—and across well vintages and operators[53,54]. Whether such heterogeneity is consequential for air-quality disparities should be a subject of future research as field-level emissions data become available.

Next, we model pollution dispersal using the Intervention Model for Air Pollution (InMAP) to obtain $PM_{2.5}$ concentration from oil production at the census-tract level for each projection year[55]. InMAP is a reduced-complexity dispersal model based on the Weather Research and Forecasting model coupled with Chemistry (WRF-Chem) that models secondary $PM_{2.5}$ concentrations developed by ref. 22. We followed the methods of ref. 55 and ran InMAP individually for each cluster and pollutant combination to obtain a source receptor matrix for all the extraction clusters. We then quantify the avoided mortality associated with changes in ambient $PM_{2.5}$ exposure at the census-tract level compared with the BAU scenario[56,57] using a mortality concentration-response function adapted from ref. 58. This function estimates avoided mortality using population projections (Supplementary Fig. 12), a baseline mortality rate from 2015, the percentage change in mortality associated with a 1 $\mu g\ m^{-3}$ increase in $PM_{2.5}$ exposure (0.0058 from ref. 59) and our estimated changes in ambient concentrations of $PM_{2.5}$. Last, we estimate the monetized values of avoided mortality using a US\$9.4 million (in 2019 dollars) value obtained from ref. 60. All mortality benefits are then summed over the 2020–2045 projection period and presented in net present value terms. Supplementary Notes 6 and 13 provide more details.

Labour impacts

We quantify changes in employment and worker compensation using an economic input–output model from IMPLAN[61,62]. IMPLAN uses over 90 sources of employment data to construct measures of county-level employment and compensation based on sector-specific revenue inputs. Supplementary Table 3 summarizes the input specifications for the labour analysis. Oil production and oil prices from the projected pathways serve as the inputs to IMPLAN, which then computes resulting employment in full-time equivalent job years and total employee compensation supported by the oil and gas industry for each county with active oil and gas operations in the state. IMPLAN uses fixed multipliers to quantify local employment changes in the oil-extraction sector ('direct'), in sectors that provide inputs to oil extraction ('indirect') and in sectors where these workers spend income ('induced'). Similar to other input–output models, IMPLAN is based on a static framework where the underlying multipliers are fixed and do not change with the economic environment, which is a limitation of this model. This implies, for example, that inflation, changes in labour productivity and geographical or temporal shocks to labour markets, all of which could be the result of some of the supply-side policies we consider, cannot be incorporated in the labour-market impact analysis. Supplementary Notes 7 and 14 provide more details.

Equity impacts

To quantify distributional impacts, we use California's legal definition of a 'disadvantaged' community (DAC) using CalEnviroScreen, a scoring system based on multiple-pollution exposure and socioeconomic indicators developed by the California Environmental Protection Agency[36]. The following indicators are considered for the DAC definition: ozone concentration, $PM_{2.5}$ concentration, diesel emissions, pesticide use, toxic releases, traffic, drinking water quality, cleanup sites, groundwater threats, hazardous waste facilities, impaired water bodies, solid waste sites, asthma rate, cardiovascular disease rate, low birth weight percent, educational attainment, housing burden, linguistic isolation, poverty percent and percent unemployed. A census tract is considered disadvantaged if it has a CalEnviroScreen score above the top 25th percentile (ref. 63). We calculate the DACs ratio of health and labour impacts (that is, the share of impacts experienced by DACs) by calculating the ratio of the impact experienced by DAC census tracts to the total statewide impact. Supplementary Note 18 provides more details. Supplementary Notes 19, 36 and 37 show the advantages of finer spatial resolution analysis (census-tract level) and the errors that may be introduced by a coarser analysis conducted at the county level, especially in the ranking of equity outcomes.

Data availability

Data on assets and asset-level costs from Rystad Energy and employment and worker compensation data from IMPLAN are proprietary. All other datasets are publicly available and were collected online from California Department of Conservation, US Energy Information Administration, International Energy Agency, California Air Resources Board, California Office of Environmental Health Hazard Assessment, California Department of Finance, the Environmental Benefits Mapping and Analysis Program - Community Edition (BenMAP-CE), National Historical Geographic Information System, Congressional Budget Office, InMAP and the US Census Bureau. All publicly available datasets are available on Zenodo at https://doi.org/10.5281/zenodo.7742802 with the exception of InMAP and BenMAP-CE data, which can be downloaded directly from the software. The Zenodo repository includes raw input data files that are not proprietary, intermediate data files to run the models and final results files to create the figures. A detailed readme file includes descriptions of all data used in the study. Source data are provided with this paper.

Code availability

All code used to conduct the study is available at https://github.com/emlab-ucsb/ca-transport-supply-decarb.

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62. Clouse, C. *Understanding Labor Income (LI), Employee Compensation (EC), and Proprietor Income (PI)* (IMPLAN Group, 2020); https://implanhelp.zendesk.com/hc/en-us/articles/360024509374-Understanding-Labor-Income-LI-Employee-Compensation-EC-and-Proprietor-Income-PI-
63. *California Communities Environmental Health Screening Tool (CalEnviroScreen 3.0)* (California OEHHA, 2018); https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30

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Author contributions

R.D., P.W., K.C.M., O.D. and D.W.L. conceptualized the study and acquired the funding. R.D., P.W., K.C.M., O.D., D.H.-C., R.L., C.M., T.M., M.M. and V.T. developed the methodology and software. R.D., P.W., K.C.M., O.D., D.H.-C., R.L., C.M., T.M., M.M., S.S., V.T. and A.U. conducted the formal analysis. D.H.-C., R.L., C.M., T.M., M.M., S.S., V.T. and A.U. curated the data. R.D., P.W., K.C.M., O.D., D.W.L., D.H.-C., T.K., R.L., C.M., T.M., M.M. and V.T. wrote and edited the paper. K.C.M., O.D., D.W.L., P.W. and R.D. supervised the project.

Competing interests

The authors declare no competing interests.

Additional information

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Control Techniques Guidelines for the Oil and Natural Gas Industry

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Control Techniques Guidelines for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, North Carolina

DISCLAIMER

This report has been reviewed by EPA's Office of Air Quality Planning and Standards and has been approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use.

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
ACA	Air Compliance Advisor
ANGA	America's Natural Gas Alliance
APCD	Air Pollution Control District
API	American Petroleum Institute
AQMD	Air Quality Management District
ARCADIS	a global consulting firm
bbl/day	barrels per day
boe/day	barrels of oil equivalent per day
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
Btu/scf	British thermal unit per standard cubic feet
CAA	Clean Air Act
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
Cfm	cubic foot per minute
CFR	Code of Federal Regulations
CH4	methane
CMSA	Consolidated Metropolitan Statistical Area
CO	carbon monoxide
CO_2	carbon dioxide
CTG	Control Techniques Guidelines
E&P Tanks Program	is a personal computer-based software designed to use site-specific information to predict emission from petroleum production storage tanks
ERG	Eastern Research Group
EVRU	ejector vapor recovery units
FIP	Federal Implementation Plan
FR	Federal Register
FRED	Federal Reserve Economic Data
G	Gram
GDP	gross domestic product
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
HAP	hazardous air pollutants

Acronyms/Abbreviations	Description
HPDI database	provides production data and web-enabled analytical software tools for a wide range of oil and gas related customers
H_2S	hydrogen sulfide
ICF International	a firm that provides professional services and technology solutions in strategy and policy analysis, program management, project evaluation, and other services
IR	infrared
kg/hr/comp	kilogram per hour per component
kg/hr/source	kilogram per hour per source
kPa	kilopascals
kW	kilowatt
LAER	lowest achievable emission rate
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf/yr	million cubic feet per year
NA	Nonattainment
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NOx	nitrogen oxide
NSPS	New Source Performance Standards
O&M	operation & maintenance
OAQPS	Office of Air Quality Planning and Standards
OCCM	OAQPS Control Cost Manual
OEL	open-ended lines
OGI	optical gas imaging
OTR	Ozone Transport Region
OVA	organic vapor analyzer
PG&E	Pacific Gas & Electric
PNAS	Proceedings of the National Academy of Sciences
ppm	parts per million
Ppmv	parts per million by volume
PRV	pressure relief valve
Psi	pounds per square inch
Psia	pounds per square inch absolute
Psig	pounds per square inch gauge
PTE	potential to emit
RACT	reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
Scf	standard cubic feet
Scfh	standard cubic feet per hour

Acronyms/Abbreviations	Description
scfh-cylinder	standard cubic feet per hour-cylinder
Scfm	standard cubic feet per minute
SIP	State Implementation Plan
SO_2	sulfur dioxide
STSD	supplemental technical support document
THC	total hydrocarbons
TOC	total organic compounds
Tpy	tons per year
TSD	technical support document
TVA	toxic vapor analyzer
U.S.	United States
U.S. EIA	U.S. Energy Information Administration
U.S. EPA	U.S. Environmental Protection Agency
VOC	volatile organic compound
VRU	vapor recovery unit

1.0 INTRODUCTION

Section 172(c)(1) of the Clean Air Act (CAA) provides that state implementation plans (SIPs) for nonattainment areas must include “reasonably available control measures” including “reasonably available control technology” (RACT), for existing sources of emissions. CAA Section 182(b)(2)(A) provides that for Moderate ozone nonattainment areas, states must revise their SIPs to include RACT for each category of volatile organic compound (VOC) sources covered by control techniques guidelines (CTG) documents issued between November 15, 1990, and the date of attainment. Section 182(c) through (e) applies this requirement to states with ozone nonattainment areas classified as Serious, Severe, and Extreme. CAA Section 184(b) requires that states in ozone transport regions must revise their SIPs to implement RACT with respect to all sources of VOC in the state covered by a CTG issued before or after November 15, 1990. CAA Section 184(a) establishes a single Ozone Transport Region (OTR) comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.

The U.S. Environmental Protection Agency (EPA) defines RACT as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” 44 FR 53761 (September 17, 1979).

This CTG provides recommendations to inform state, local, and tribal air agencies (hereafter, collectively referred to as air agencies) as to what constitutes RACT for select oil and natural gas industry emission sources. Air agencies can use the recommendations in the CTG to inform their own determination as to what constitutes RACT for VOC for the emission sources presented in this document in their Moderate or higher ozone nonattainment area or state in the OTR. The information contained in this document is provided only as guidance. This guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA’s regulations; nor is it a regulation itself. This document does not impose any requirements on facilities in the oil and natural gas industry. It provides only recommendations for air agencies to consider in determining RACT. Air agencies may implement other technically-sound approaches that are consistent with the CAA, the EPA's implementing regulations, and policies on interpreting RACT.

The recommendations contained in this CTG are based on data and information currently available to the EPA. The EPA evaluated the sources of VOC emissions in the oil and natural gas industry and the available control approaches for addressing these emissions, including the costs of such approaches. The recommendations contained in this CTG may not be appropriate for every situation based upon the circumstances of a specific source (e.g., VOC content of the gas, safety concerns/reasons). Regardless of whether an air agency chooses to adopt rules implementing the recommendations contained herein, or to issue rules that adopt different approaches for RACT for VOC from oil and natural gas industry sources, air agencies must submit their RACT rules to the EPA for review and approval using the SIP process. The EPA will evaluate the RACT determinations and determine, through notice and comment rulemaking, whether these determinations in the submitted rules meet the RACT requirements of the CAA and the EPA's regulations. To the extent an air agency adopts any of the recommendations in this guidance into its RACT rules, interested parties can raise questions and objections about the appropriateness of the application of this guidance to a particular situation during the development of these rules and the EPA's SIP process. Such questions and objections can relate to the substance of this guidance.

Section 182(b)(2) of the CAA requires that a CTG document issued between November 15, 1990, and the date of attainment include the date by which states subject to CAA section 182(b) must submit SIP revisions. Accordingly, the EPA is setting forth a 2-year period, from the date of publication of the notice of availability of this CTG in the *Federal Register* for the required SIP submittal.

2.0 BACKGROUND AND OVERVIEW

There have been several federal and state actions to reduce VOC emissions from certain emission sources in the oil and natural gas industry. A summary of these actions is provided below.

2.1 History of New Source Performance Standards that Regulate Emission Sources in the Oil and Natural Gas Industry

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). Since the 1979 listing, the EPA has promulgated performance standards to regulate VOC emissions from production, processing, transmission, and storage as well as sulfur dioxide (SO_2) emissions from natural gas processing emission sources and, more recently, greenhouse gases (GHG). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for natural gas processing plants that addressed VOC emissions from leaking components (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for natural gas processing plants that regulated SO_2 emissions (40 CFR part 60, subpart LLL). On August 16, 2012 (77 FR 49490) (2012 NSPS), the EPA finalized its review of NSPS standards for the listed oil and natural gas source category and revised the NSPS for VOC from leaking components at natural gas processing plants, and the NSPS for SO_2 emissions from natural gas processing plants. At that time, the EPA also established standards for certain oil and natural gas emission sources not covered by the existing standards. In addition to the emission sources that were covered previously, the EPA established new standards to regulate VOC emissions from hydraulically fractured gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, and storage vessels. In 2013 (78 FR 58416) (2013 NSPS Reconsideration) and 2014 (79 FR 79018), the EPA amended the standards set in 2012 in order to improve implementation of the standards. In 2016 (81 FR 35824, June 3, 2016), the EPA finalized new standards to regulate GHG and VOC emissions across the oil and natural gas source category. Specifically, the EPA finalized both GHG standards (in the form of limitations on methane emissions) and VOC standards for several emission sources not previously covered by the NSPS (i.e., hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations).

In addition, the EPA finalized GHG standards for certain emission sources that were regulated for only VOC (i.e., hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers and equipment leaks at natural gas processing plants). With respect to certain equipment that are used across the industry, 40 CFR part 60 subpart OOOO regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The final amendments established GHG standards (40 CFR part 60 subpart OOOOa) for these equipment and extended the current VOC standards to previously unregulated equipment. Although not regulated under the oil and natural gas NSPS, stationary reciprocating internal combustion engines and combustion turbines used in the oil and natural gas industry are covered under separate NSPS specific to engines and turbines (40 CFR part 60, subparts IIII, JJJJ, GG, KKKK).

In addition to NSPS issued to regulate VOC emissions from the oil and gas industry, the EPA also published a CTG document that recommended the control of VOC emissions from equipment leaks from natural gas processing plants in 1983 (1983 CTG; 49 FR 4432; February 6, 1984).[1] This 2016 CTG is the only CTG document issued since 1983 for the oil and natural gas industry.

2.2 State and Local Regulations

Several states regulate VOC emissions from storage vessels in the oil and natural gas industry. There are also a few states (e.g., Colorado, Wyoming, and Montana) that have established specific permitting requirements or regulations that control VOC emissions from emission sources in the oil and natural gas industry (e.g., compressors, pneumatics, fugitive emission components):

(1) The Colorado Department of Public Health and Environment, Air Quality Control Commission has developed emission regulations 3, 6, and 7 that apply to oil and natural gas industry emission sources in Colorado. (https://www.colorado.gov/pacific/cdphe/summary-oil-and-gas-emissions-requirements.)

(2) Montana requires oil and gas well facilities to control emissions from the time the well is completed until the source is registered or permitted (Registration of Air Contaminant

[1] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

Sources Rule, Rule 17.8.1711, Oil or Gas Well Facilities Emission Control Requirements). (http://www.mtrules.org/gateway/ruleno.asp?RN=17%2E8%2E1711.)

(3) The Wyoming Department of Environmental Quality limits VOC emissions from existing sources in ozone nonattainment areas and has issued specific permitting guidance that apply to oil and natural gas facilities. (Chapter 6, Section 2 Permitting Guidance, last revised in September 2013).

(4) The San Joaquin Valley Air Pollution Control District requires control of VOC emissions from several VOC oil and natural gas emission sources, including, but not limited to, (a) storage vessels, (b) crude oil production sumps, (c) components at light crude oil production facilities, natural gas production facilities and natural gas processing facilities, and (d) in-situ combustion well vents.

In some states, general permits have been developed for oil and natural gas facilities.

General permits are permits where all the terms and conditions of the permit are developed for a given industry and authorize the construction, modification, and/or operation of facilities that meet those terms and conditions. For example, West Virginia, Ohio, and Pennsylvania have developed General Air Permits for the oil and natural gas industry. The Pennsylvania Department of Environmental Protection has issued a General Permit, General Plan Approval and Permit Exemption 38 for natural gas dispensing facilities and oil and gas exploration, development, and production operations. Pennsylvania also applies conditions on flaring of emissions. Under the Permit 38 exemptions, there are criteria set out for the oil and natural gas industry that include unconditionally exempt and conditionally exempt criteria. Unconditionally exempt operations/equipment include conventional wells, conventional wellheads and associated equipment, well drilling, completion and work-over activities, and non-road engines. Unconventional wells, wellheads and associated equipment (including equipment components, storage vessels) are conditionally exempt. Conditions include compliance with 40 CFR part 60, subpart OOOO and Pennsylvania's General Permit 5 (GP-5) and a demonstration that the combined VOC emissions from all sources at a facility are less than 2.7 tons per year (tpy) on a 12-month rolling basis. For oil and natural gas facilities that do not meet these conditions, a case-by-case plan approval is required.[2]

There may also be local permit requirements for control of VOC emissions from existing sources of VOC emissions in the oil and natural gas industry, such as those required by the Bay Area Air Quality Management District (BAAQMD) for pneumatic controllers. The BAAQMD requires that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in their permit application. Facilities that use high-bleed devices might be required to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where emissions are high from high-bleed devices, BAAQMD might require that the facility conduct fugitive monitoring and/or control requirements under conditions of their permit to operate[3] on a case-by-case basis.

We conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and identified several draft and final permits that covered some of the sources evaluated for RACT in this CTG. The controls specified in these permits are similar to the control options evaluated in this CTG.[4]

We considered these existing state and local requirements limiting VOC emissions from the oil and natural gas industry in preparing this guideline.

2.3 Development of this CTG

As discussed in section 2.1 of this chapter, the NSPS established VOC emission standards for certain new and modified sources in the oil and gas industry. This CTG addresses existing sources of VOC emissions and provides recommendations for RACT for the oil and natural gas industry. We developed our RACT recommendations after reviewing the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on costs, emissions and available VOC emission control technologies. In April 2014, the EPA released five technical white papers on potentially significant sources of emissions in the oil and natural gas industry. The white papers focused on

[2] Pennsylvania Department of Environmental Protection. *Comparison of Air Emission Standards for the Oil & Natural Gas Industry* (Well Pad Operations, Natural Gas Compressor Stations, and Natural Gas Processing Facilities). May 23, 2014.
[3] Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities.* Bay Area Air Quality Management District. September 16, 2013.
[4] RACT/BACT/LAER Clearinghouse website: http://cfpub.epa.gov/RBLC/.

technical issues covering emissions and mitigation techniques that target methane and VOC. We reviewed the white papers, along with the input we received from the peer reviewers and the public, when evaluating and recommending RACT.

This CTG reflects the evaluation of potential RACT options for emission sources that are regulated under the oil and natural gas NSPS. This CTG did not evaluate hydraulically fractured oil and natural gas well completions performed on existing wells because these operations are addressed in the NSPS.

Several of the technical support documents (TSDs) prepared in support of the NSPS actions for the oil and natural gas industry include data and analyses considered in developing RACT recommendations in this CTG. To the extent that the data and analyses are also relevant to control options for existing sources, they are referred to throughout this guidance document as follows:

(1) The TSD for the 2011 NSPS proposal, published in July, 2011 is referred to as the "2011 NSPS TSD".[5]
(2) The supplemental TSD for the 2012 final NSPS standards, published in April, 2012, is referred to as the "2012 NSPS TSD" or "2012 NSPS STSD"[6]
(3) The TSD for the 2015 proposal NSPS standards, published August, 2015, is referred to as the "2015 NSPS TSD".[7]
(4) The TSD for the 2016 final NSPS standards, published in May, 2016, is referred to as the "2016 NSPS TSD"[8]

Additionally, emission information and counts for various emission sources were summarized from facility-level data submitted to the Greenhouse Gas Reporting Program

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[5] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA-453/R-11002.
[6] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. Docket ID No. EPA-HQ-OAR-2010-0505-4550.
[7] U.S. Environmental Protection Agency. *Oil and Natural Gas Source Category: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards.* August 2015. (See Docket No. EPA-HQ-OAR-2010-0505-5021; regulations.gov).
[8] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources – Background Technical Support Document for the Final New Source Performance Standards*. May 2016.

(GHGRP)[9] and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory).[10] For the purposes of this document, these data sources are referred to as the “GHGRP” and the “GHG Inventory”. The most recent published data from the GHG Inventory when we prepared the draft CTG was for 2013, and was used for some of the analyses included in this document. Between the time we issued the draft CTG and the final CTG, GHGRP data was released that covers 2011 through 2014 and the most recent available GHG Inventory covers data from 1990 through 2014. These new activity data have been reviewed for this CTG and incorporated into our RACT analyses, as appropriate.

Most of the VOC emission estimates presented in this document are based on methane emissions data because we only had methane emissions information for the evaluated sources. We calculated VOC emissions using ratios of methane to VOC in the gas for the different segments of the industry. These ratios, and the procedures used to calculate them, are documented in a memorandum characterizing gas composition developed during the NSPS process. [11] Herein, we refer to this memorandum as the “2011 Gas Composition Memorandum”. Because methane emissions are the basis for most of our VOC emission estimates, in several instances where we provide VOC emissions per source/model plant, we also provide the methane emissions that are the basis for our VOC emission estimates.

The remainder of this document is divided into seven chapters and an appendix. Chapter three describes the oil and natural gas industry and a summary of our RACT recommendations presented in this CTG. Chapters four through nine describe the oil and natural gas emission sources that we evaluated for our RACT recommendations (i.e., storage vessels, compressors, pneumatic controllers, pneumatic pumps, equipment component leaks from natural gas processing plants, and fugitive emissions from well sites and gathering and boosting stations), available control and regulatory approaches (including existing federal, state and local requirements) and the potential emission reductions and costs associated with available control and regulatory approaches for a given emission source. The appendix provides example model

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[9] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014. (Reported Data: http://www.epa.gov/ghgreporting/). The Greenhouse Gas Reporting Program has particular definitions of “facility” for certain petroleum and natural gas systems industry segments. See 40 CFR 98.238.
[10] U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2014*. Washington, DC. EPA 430-R-15-004. Available online at https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014.
[11] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.

rule language that can be used by air agencies as a starting point in the development of their SIP rules if they choose to adopt the recommended RACT presented in this document.

3.0 OVERVIEW OF THE OIL AND NATURAL GAS INDUSTRY AND SOURCES SELECTED FOR RACT RECOMMENDATIONS

Section 3.1 presents an overall description of the oil and natural gas industry and section 3.2 presents the VOC emission sources for which we are recommending RACT within the oil and natural gas industry. Table 3-1 provides a summary of recommendations for controlling VOC emissions from oil and natural gas industry emission sources.

3.1 Overview of the Oil and Natural Gas Industry

The oil and natural gas industry includes oil and natural gas operations involved in the extraction and production of crude oil and natural gas, as well as the processing, transmission, storage, and distribution of natural gas. For oil, the industry includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the industry includes all operations from the well to the customer. For purposes of this document, the oil and natural gas operations are separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution. We briefly discuss each of these segments below. For purposes of this CTG, oil and natural gas production includes only onshore operations.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head, and “Christmas tree” piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices, and dehydrators. Production operations also include well drilling, completion, and recompletion processes, which include all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the “pads” where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production segment also includes the low-pressure, small diameter, gathering pipelines and related components that collect and transport the oil, natural gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

There are two basic types of wells: oil wells and natural gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar, or pipeline. The oil refinery sector is considered separately from the oil and natural gas industry. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

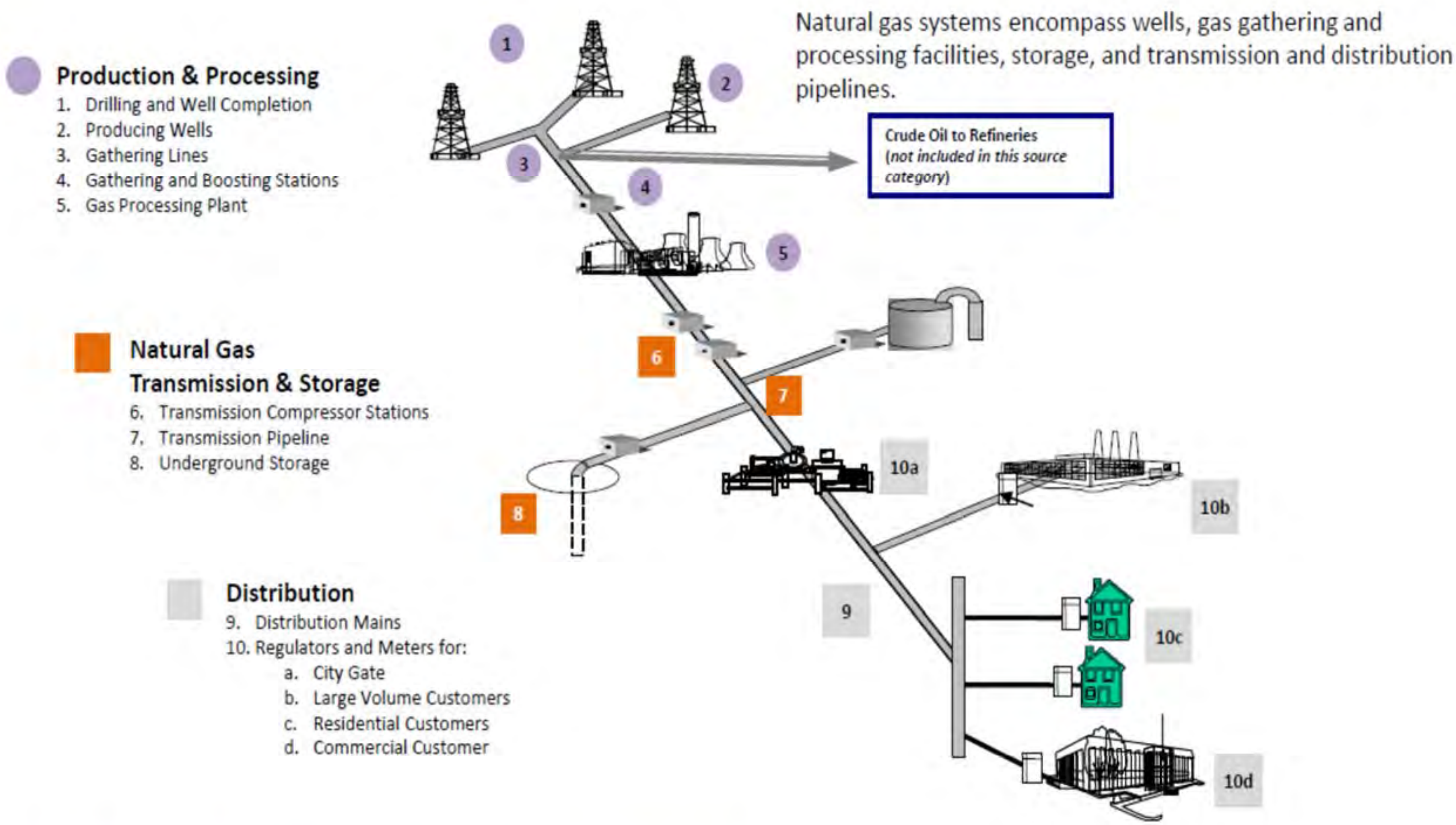
Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen, and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids (NGL) or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid, and other processes such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

The pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment. Pipelines in the natural gas transmission and storage segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration, and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of natural gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas industry. Primarily, these emissions are organic compounds such as methane, ethane, VOC, and organic hazardous air pollutants (HAP). Figure 3-1 presents a schematic of oil and natural gas sector operations.



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure 3-1. Oil and Natural Gas Sector Operations

3.2 Sources Selected For RACT Recommendations

This CTG covers select sources of VOC emissions in the onshore production and processing segments of the oil and natural gas industry (i.e., pneumatic controllers, pneumatic pumps, compressors, equipment leaks, fugitive emissions) and storage vessel VOC emissions in all segments (except distribution) of the oil and natural gas industry. These sources were selected for RACT recommendations because current information indicates that they are significant sources of VOC emissions. As mentioned in section 2.3, the VOC RACT recommendations contained in this document were made based on the review of the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on emissions, available VOC emission control technologies, and costs.

In considering costs, we compared control options and estimated costs and emission impacts of multiple emission reduction options under consideration. Recommendations are presented in this CTG for the subset of existing sources in the oil and natural gas industry where the application of controls is judged reasonable, given the availability of demonstrated control technologies, emission reductions that can be achieved, and the cost of control.

Table 3-1 presents a summary of the oil and natural gas emission sources and recommended RACT included in this CTG.

Table 3-1. Summary of the Oil and Natural Gas Industry Emission Sources and Recommended RACT Included in this CTG

Emission Source	Applicability	RACT Recommendations
Storage Vessels	Individual storage vessel with a potential to emit (PTE) greater than or equal to 6 tpy VOC.	95 percent reduction of VOC emissions from storage vessels. OR Maintain less than 4 tpy uncontrolled actual VOC emissions after having demonstrated that the uncontrolled actual VOC emissions have remained less than 4 tpy, as determined monthly, for 12 consecutive months.
Pneumatic Controllers	Individual continuous bleed, natural gas-driven pneumatic controller located at a natural gas processing plant.	Natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).
	Individual continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.	Natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).
Pneumatic Pumps	Individual natural gas-driven diaphragm pump located at a natural gas processing plant.	Zero VOC emissions.
	Individual natural gas-driven diaphragm pump located at a well site.	Require routing of VOC emissions from the pneumatic pump to an existing onsite control device or process.
		Require 95 percent control unless the onsite existing control device or process cannot achieve 95 percent.
		If onsite existing device or process cannot achieve 95 percent, maintain documentation demonstrating the percent reduction the control device is designed to achieve.

Emission Source	Applicability	RACT Recommendations
		If there is no existing control device at the location of the pneumatic pump, maintain records that there is no existing control device onsite.
	Individual natural gas-driven diaphragm pump located at a well site that is in operation for any period of time each calendar day for less than a total of 90 days per calendar year.	RACT would not apply.
Compressors (Centrifugal and Reciprocating)	Individual reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions by replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement. Alternatively, route rod packing emissions to a process through a closed vent system under negative pressure.
	Individual reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95 percent.
	Individual centrifugal compressor using wet seals located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using dry seals.	RACT would not apply.
Equipment Leaks	Equipment components in VOC service located at a natural gas processing plant.	Implement the 40 CFR part 60, subpart VVa leak detection and repair (LDAR) program for natural gas processing plants.
Fugitive Emissions	Individual well site with wells with a gas to oil ratio (GOR) greater than or equal to 300, that produce, on average, greater than 15 barrel equivalents per well per day.	Develop and implement a semiannual optical gas imaging (OGI) monitoring and repair plan that covers the collection of fugitive emissions components at well sites within a company defined area. Method 21 can be

Emission Source	Applicability	RACT Recommendations
		used as an alternative to OGI at a 500 ppm repair threshold level.
	Individual gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline.	Develop and implement a quarterly OGI monitoring and repair plan that covers the collection of fugitive emissions components at gathering and boosting stations within a company defined area. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.
	Individual well site with a GOR less than 300.	RACT would not apply.

4.0 STORAGE VESSELS

Storage vessels are significant sources of VOC emissions in the oil and natural gas industry. This chapter provides a description of the types of storage vessels present in the oil and natural gas industry, and provides VOC emission estimates for storage vessels, in terms of mass of emissions per throughput, for both crude oil and condensate storage vessels. This chapter also presents control techniques used to reduce VOC emissions from storage vessels, along with their costs and potential emission reductions. Finally, this chapter provides a discussion of our recommended RACT for storage vessels.

4.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to a tank or other vessel in the oil and natural gas industry that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) that provide structural support. The emissions and emission controls discussed herein would not apply to the following vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), and are intended to be located at a site for less than 180 consecutive days.

(2) Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.[12]

4.2 Process Description and Emission Sources

4.2.1 Process Description

Storage vessels in the oil and natural gas industry are used to hold a variety of liquids including crude oil, condensates, produced water, etc. While still underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the

[12] It is acknowledged that even pressure vessels designed to operate without emissions have a small potential for fugitive emissions at valves. Valves are threaded components that would be subject to leak detection and repair requirements.

surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed and any oil and water remain together) or a three-phase separator (where the associated gas is removed and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the hydrocarbons from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into an atmospheric storage vessel from a processing vessel (e.g., a separator) operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and other equilibrium effects. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also may include ethane, butane, propane, and HAP such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane.

4.2.2 Emissions Data

4.2.2.1 Summary of Major Studies and Emissions

There are numerous studies and reports available that estimate storage vessel emissions. We consulted several of these studies and reports to evaluate the emissions and emission reduction options for storage vessels. Table 4-1 presents a summary of the references for these reports, along with an indication of the type of information available in each reference.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data[a,b]

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[e]
VOC Emissions from Oil and Condensate Storage Tanks	Texas Environmental Research Consortium	2009	Regional	X	X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economic Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number 7	Colorado Air Quality Control Commission	2008	NA		X
E&P TANKS	API		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[c]	EPA	Annual	National	X	
Greenhouse Gas Reporting Program (Annual Reporting: Current Data Available for 2011-2013)[d]	EPA	2014	Facility-Level	X	X

NA = Not Applicable.
[a] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No. EPA-HQ-OAR-2010-0505-4550.
[b] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Technical Support*. July 2011. EPA-453/R-11-002.
[c] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[d] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.
[e] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

4.2.2.2 Representative Storage Vessel Baseline Emissions

Storage vessels vary in size and throughputs. In support of the 2013 NSPS Reconsideration,[13] average storage vessel emissions, in terms of mass of emissions per throughput, were developed for both crude oil and condensate storage vessels.[14] We also developed mass emissions per throughput estimates using the American Petroleum Institute's (API's) E&P TANKS program and more than 100 storage vessels across the country with varying characteristics.[15] The VOC emissions per throughput estimates used for this analysis are:

(1) Uncontrolled VOC Emissions from Crude Oil Storage Vessels = 0.214 tpy VOC/barrel per day (bbl/day); and

(2) Uncontrolled VOC Emissions from Condensate Storage Vessels = 2.09 tpy VOC/bbl/day.

On a nationwide basis, there are a wide variety of storage vessel sizes, as well as rates of throughput for each tank. Emissions are directly related to the throughput of liquids for a given storage vessel; therefore, in support of the 2013 NSPS Reconsideration, we adopted production rate brackets developed by the U.S. Energy Information Administration (U.S. EIA) for our emission estimates. To estimate the emissions from an average storage vessel within each production rate bracket, we developed average production rates for each bracket. This average was calculated using the U.S. EIA published nationwide production per well per day for each production rate bracket from 2006 through 2009. Table 4-2 presents the average oil production and condensate production in barrels per well per day. For this analysis, we considered the liquid produced (as reported by the U.S. EIA) from oil wells to be crude oil and from gas wells to be condensate. Table 4-2 presents the average VOC emissions for each storage vessel within each production rate bracket calculated by applying the average production rate (bbl/day) to the VOC emissions per throughput estimates (tpy VOC/bbl/day).

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[13] 78 FR 58416, September 23, 2013. The EPA issued final updates to its 2012 VOC performance standards for storage tanks used in crude oil and natural gas production and transmission. The amendments reflected updated information that responded to issues raised in several petitions for reconsideration of the 2012 standards.

[14] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

[15] American Petroleum Institute. *Production Tank Emissions Model. E&P Tank Version 2.0. A Program for Estimating Emissions from Hydrocarbon Production Tanks*. Software Number 4697. April 2000.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[16]

Production Rate Bracket (BOE/day)[a]	Oil Wells: Average Oil Production Rate per Oil Well (bbl/day)[b]	Oil Wells: Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Gas Wells: Average Condensate Production Rate per Gas Well (bbl/day)[b]	Gas Wells: Condensate Storage Vessel VOC Emissions (tpy)[c]
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a] BOE=Barrels of Oil Equivalent
[b] Oil and condensate production rates published by U.S. EIA. "United States Total Distribution of Wells by Production Rate Bracket."
[c] Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.
[d] There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

[16] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

4.3 Available Controls and Regulatory Approaches

In analyzing available controls for storage vessels, we reviewed information obtained in support of the 2012 NSPS[17] and the 2013 NSPS Reconsideration actions, control techniques identified in the Natural Gas STAR program, and existing state regulations that require control of VOC emissions from storage vessels in the oil and natural gas industry. Section 4.3.1 presents a non-exhaustive discussion of available VOC emission control methods for storage vessels. Section 4.3.2 includes a summary of the federal, state, and local regulatory approaches that control VOC emissions from crude oil and condensate storage vessels.

4.3.1 Available VOC Emission Control Options

The options generally used as the primary means to limit the amount of VOC vented are to: (1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – "route to a process" (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite and/or (2) route emissions from the storage vessel to a combustion device. While EPA explored these options within the document, there may be other emission controls that sources may wish to employ to ensure continuous compliance with EPA's RACT recommendation. Regardless of the type of emission control method that a source may choose to utilize, the recommended RACT level of control explained more fully below is meant to apply at all times. One of the clear advantages the first option has over the second option is that it results in a cost savings associated with the recycled, recovered and reused natural gas and other hydrocarbon vapor, rather than the loss and destruction of the natural gas and vapor by combustion. Combustion and partial combustion of organic pollutants also creates secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide and smoke/particulates. These emission control methods are described below along with their emission reduction control effectiveness as they apply to storage vessels in the industry and the potential costs associated with their installation and operation.

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[17] *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.

4.3.1.1 Routing Emissions to a Process via a Vapor Recovery Unit (VRU)

Description

One option for controlling storage vessel emissions is to route vapors from the storage vessel back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbon fluids for beneficial use, such as use as a fuel. Where a compressor is used to boost the recovered vapors into the line, this is often referred to as a VRU.[18] Typically with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are usually recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite.

Types of VRUs include conventional VRUs and venturi ejector vapor recovery units (EVRU™) or vapor jet systems.[19] Decisions on the type of VRU to use are based on the applicability needs (e.g., an EVRU™ is recommended where there is a high-pressure gas compressor with excess capacity and a vapor jet VRU is suggested where there is produced water, less than 75 million cubic feet (MMcf)/day gas and discharge pressures below 40 pounds per square inch gauge (psig)). The reliability and integrity of the compressor and suction scrubber and integrity of the lines that connect the tank to the compressor will affect the effectiveness of the VRU system to collect and recycle vapors.[20]

A conventional VRU is equipped with a control pilot to shut down the compressor and permit the back flow of vapors into the tank in order to prevent the creation of a vacuum in the top of a tank when liquid is withdrawn and the liquid level drops. Vapors are then either sent to the pipeline for sale or used as onsite fuel. Figure 4.1 presents a diagram of a conventional VRU installed on a single crude oil storage vessel (multiple tank installations are also common).[21]

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[18] American Petroleum Institute. Letter to Bruce Moore, SPPD/OAQPS/EPA from M. Todd, API. *Re: Oil and Natural Gas Sector Consolidated Rulemaking*. Docket ID No. EPA-HQ-OAR-2010-0505.
[19] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units.* Natural Gas STAR Program. Source Reduction Training to Interstate Oil and Gas Compact Commission Presentation. February 27, 2009.
[20] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks*. Natural Gas STAR Program. October 2006.
[21] Ibid.

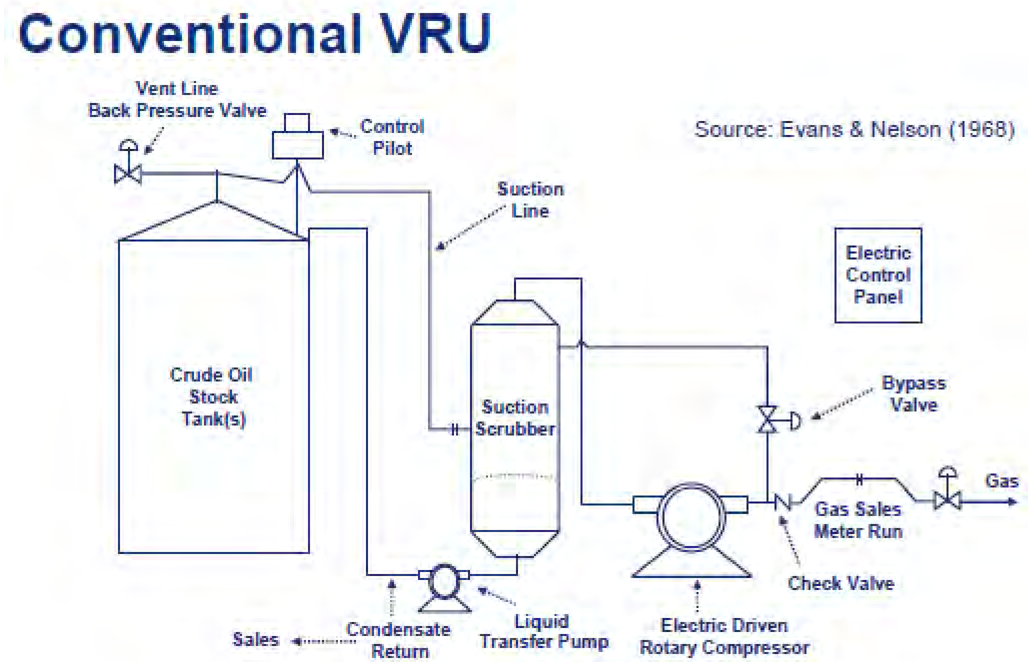

Figure 4-1. Conventional Vapor Recovery System

<u>Control Effectiveness</u>

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by over 95 percent.[22] When operating properly, VRUs generally approach 100 percent efficiency. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, our analysis assumes a 95 percent reduction in VOC emissions for a VRU. A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU cannot be used in all instances. Conditions that affect the feasibility of the use of a VRU include: the availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

[22] Ibid.

Cost Impacts

Cost data for a VRU obtained from an initial economic impact analysis prepared for proposed state-only revisions to a Colorado regulation are presented here.[23] We assumed cost information contained in the Colorado economic impact analysis to be given in 2012 dollars. According to the Colorado economic impact analysis, the cost of a VRU was estimated to be $90,000. Including costs associated with freight and design, and the cost of VRU installation, we estimated costs to be $102,802 ($90,000 plus $12,802). We also added an estimated storage vessel retrofit cost of $68,736 assuming that the cost of retrofitting an existing storage vessel was 75 percent of the purchased equipment cost (i.e., VRU capital cost and freight and design cost).[24] Based on these costs, we estimated the total capital investment of the VRU to be $171,538. These cost data are presented in Table 4-3. We estimated total annual costs using 2012 dollars to be $28,230 per year without recovered natural gas savings. The uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities.

In order to assess the cost of control of a VRU for uncontrolled storage vessels that emit differing emissions, we evaluated the cost of routing VOC emissions from an existing uncontrolled storage vessel to a VRU for a storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy, and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU and converting the reduced VOC emissions to natural gas savings. Table 4-4 presents the estimated natural gas savings and the VOC cost per ton of VOC reduced with and without savings.

[23] Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.
[24] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks.* Natural Gas STAR Program. October 2006.

Table 4-3. Total Capital Investment and Total Annual Costs of a Vapor Recovery Unit System

Cost Item[a]	Cost ($2012)
Capital Cost Items	
VRU[a]	$90,000
Freight and Design[a]	$1,648
VRU Installation[a]	$11,154
Storage Vessel Retrofit[b]	$68,736
Total Capital Investment	$171,538
Annual Cost Items	
Maintenance	$9,396
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$18,834
Total Annual Costs w/o Savings ($/yr)	***$28,230***

[a] Cost data from the Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
[b] Assumes the storage vessel retrofit cost is 75 percent of the purchased equipment price (assumed to include vent system and piping to route emissions to the control device). Retrofit assumption from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, *Installing Vapor Recovery Units on Storage Tanks*. October 2006.

Table 4-4. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)		
	Without Savings	Natural Gas Savings (Mscf/yr)[a]	With Savings[b]
2	$14,858	59	$14,734
4	$7,429	118	$7,305
6	$4,953	177	$4,828
8	$3,714	236	$3,590
10	$2,972	295	$2,847
12	$2,476	353	$2,352
25	$1,189	736	$1,065

[a] The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.
[b] Assumes a natural gas price of $4.00 per Mcf.

Additionally, if a VRU is used to control VOC emissions from multiple storage vessels, the VOC emissions cost of control would be reduced because the cost for the additional storage vessel(s) would only include the storage vessel retrofit costs, and the overall VOC emission reductions would increase.

4.3.1.2 Routing Emissions to a Combustion Device

Description and Control Effectiveness

Combustors (e.g., enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) are also used to control emissions from storage vessels. Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[25] For this analysis, we assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuing basis. [26] We note that combustion devices can be designed to meet 98 percent control efficiencies, and can control, on average, emissions by 98 percent or more in practice when properly operated.[27] We also recognize that combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions.

A typical combustor used to control emissions from storage vessels in the oil and natural gas industry is an enclosed combustion system. The basic components of an enclosed combustion system include (1) piping for collecting emission source gases, (2) a single- or multiple-burner unit, (3) a stack enclosure, (4) a pilot flame to ignite the mixture of emission source gas and air and (5) combustor fuel/piping (as necessary). Figure 4-2 presents a schematic of a typical dual-burner enclosed combustion system.

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[25] U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I, *Chapter 13.5 Industrial Flares*. Office of Air Quality Planning & Standards. 1991.

[26] U.S. Environmental Protection Agency. *Air Pollution Control Technology Fact Sheet: FLARE*. Clean Air Technology Center.

[27] The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed that they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. The EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

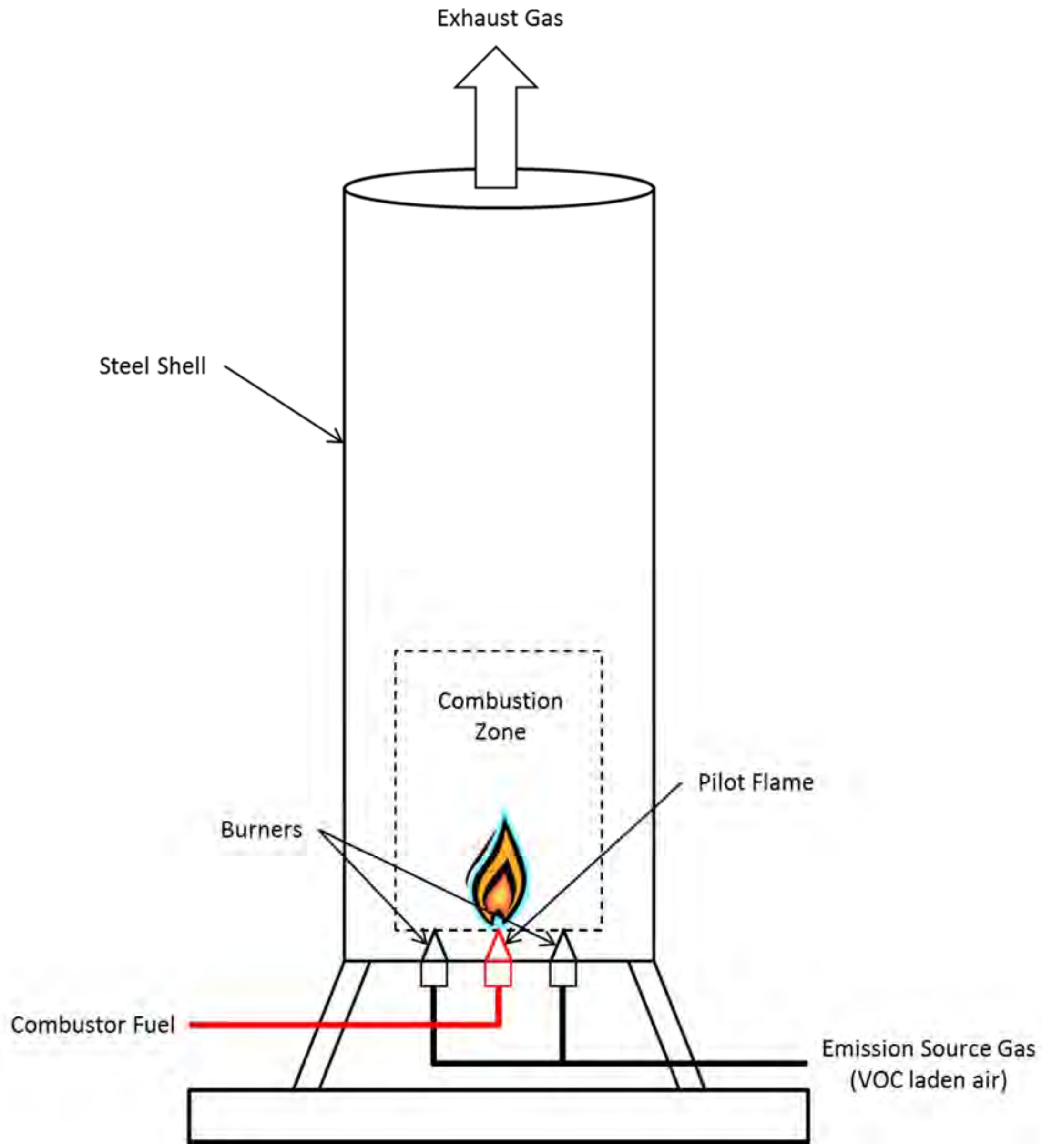

Figure 4-2. Schematic of a Typical Enclosed Combustion System

Thermal oxidizers, also referred to as direct flame incinerators, thermal incinerators, or afterburners, could also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted to the atmosphere. Figure 4-3 provides a basic schematic of a thermal oxidizer.[28]

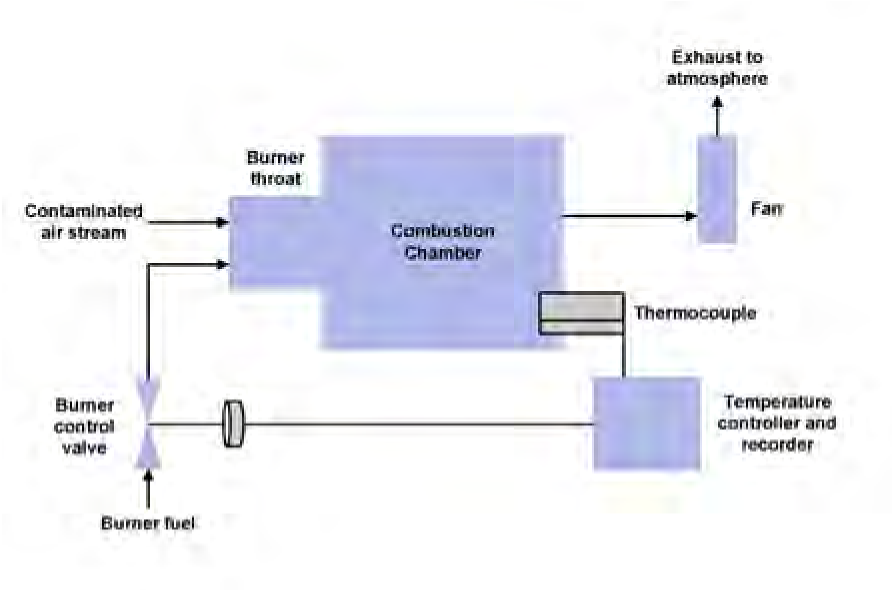

Figure 4-3. Basic Schematic of a Thermal Oxidizer

<u>Cost Impacts</u>

For combustion devices, we obtained cost data from the initial economic impact analysis prepared for state-only revisions to the Colorado regulation.[29] In addition to these cost data, we added line items for operating labor, a surveillance system and data management. This is consistent with the guidelines outlined in the EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (OCCM) for combustion devices and the cost analysis prepared for the 2012 NSPS.[30,31] However, OCCM guidelines specify 630 operating labor hours

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[28] U.S. Environmental Protection Agency. Technology Transfer Network. Clearinghouse for Inventories and Emission Factors. *Thermal Oxidizer*. Website: https://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=17.
[29] Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.
[30] *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.
[31] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

per year for a combustion device, which we believe is unreasonable because many of these sites are unmanned and would most likely be operated remotely. Therefore, we assumed that the operating labor would be more similar to that estimated for a condenser in the OCCM, 130 hours per year. We estimated a total capital investment of $100,986 and total annual costs of $25,194 per year. The total capital investment cost includes a storage vessel retrofit cost of $68,736 (as discussed previously for VRUs) to accommodate the use of a combustion device. These cost data are presented in Table 4-5.

Table 4-5. Total Capital Investment and Total Annual Costs of a Combustor[32]

Cost Item[a]	**Cost ($2012)**
Capital Cost Items	
Combustor[a]	$18,169
Freight and Design[a]	$1,648
Auto Ignitor[a]	$1,648
Surveillance System[b,c,d]	$3,805
Combustor Installation[a]	$6,980
Storage Vessel Retrofit[e]	$68,736
Total Capital Investment	$100,986
Annual Cost Items	
Operating Labor[f]	$5,155
Maintenance Labor[f]	$4,160
Non-Labor Maintenance[a]	$2,197
Pilot Fuel	$1,537
Data Management[c]	$1,057
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$11,088
Total Annual Cost ($/yr)	$25,194

[a] Cost data from Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
[b] Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.

[32] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[c] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No.EPA-HQ-OAR-2010-0505-4550.
[d] Cost obtained from 2012 NSPS TSD and escalated using the change in GDP: Implicit Price Deflator from 2008 to 2012 (percent)(which was 5.69 percent). Source: FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (http://research.stlouisfed.org/fred2/series/GDPDEF/#).
[e] Retrofit cost obtained from Storage Vessel Retrofit in Table 4-3 (assumed to include vent system and piping to route emissions to the control device).
[f] Operating labor consists of labor resources for technical operation of device (130 hr/yr) and supervisory labor (15 percent of technical labor hours). Maintenance labor hours are assumed to be the same as operating labor (130 hr/yr). Labor rates are $32.00/hr (for technical and maintenance labor) and $51.03 (supervisory labor) and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics, Employer Costs for Employee Compensation, December 2012. Labor rates account for total compensation (wages/salaries, insurance, paid leave, retirement and savings, supplemental pay and legally required benefits).

As noted previously, storage vessels vary in size and throughputs and the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and cost of control. In order to assess the cost of control of combustion for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. Table 4-6 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-6. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a Combustion Device ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)
2	$13,260
4	$6,630
6	$4,420
8	$3,315

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)
10	$2,652
12	$2,411
25	$2,210

4.3.1.3 Routing Emissions to a VRU with a Combustion Device as Backup

Industry practice also includes the primary operation of a VRU and secondary operation of a combustion device during VRU maintenance and other times requiring VRU downtime. Using the costs for a VRU and combustion device presented in sections 4.3.1.1 and 4.3.1.2, and assuming the VRU is operated 95 percent of the year and a combustion device is operated 5 percent of the year, we estimated total annual costs using 2012 dollars to be $32,006 per year without recovered natural gas savings. As stated previously, the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities, as well as the percent of time that a VRU is down during the year where emissions are routed to a combustion device. In order to assess the cost of control of a VRU with the use of a combustion device during downtime for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a VRU/combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU (used 95 percent of the year) and converting the reduced VOC emissions to natural gas savings. Table 4-7 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a VRU/combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-7. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU/Combustion Device ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)		
	Without Savings	Natural Gas Savings (Mscf/yr)[a]	With Savings[b]
2	$16,845	56	$16,728
4	$8,423	112	$8,305
6	$5,615	168	$5,497
8	$4,211	224	$4,094
10	$3,369	280	$3,251
12	$2,808	336	$2,690
25	$1,348	699	$1,230

[a] The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.
[b] Assumes a natural gas price of $4.00 per Mcf.

4.3.2 Existing Federal, State and Local Regulations

4.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2013 NSPS Reconsideration, new or modified storage vessels with PTE VOC emissions of 6 tpy or more must reduce VOC emissions by at least 95 percent, or demonstrate emissions from a storage vessel have dropped to less than 4 tpy of VOC without emission controls for 12 consecutive months.

4.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions[33]

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and how the source must be operated. To ensure that sources

[33] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector.* 2013.

follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

The environmental regulations in nine of the top oil and natural gas producing states (sometimes with varying local ozone nonattainment area/concentrated area development requirements) (see Table 4-8) require the control of VOC emissions from storage vessels in the oil and natural gas industry. These states include California, Colorado, Kansas, Louisiana, Montana, North Dakota, Oklahoma, Texas, and Wyoming. All except Wyoming require 95 percent emission control with the application of a VRU or combustion (Wyoming requires 98 percent control of emissions using a VRU or combustion).

Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Table 4-8 presents a brief summary of the storage vessel emission control applicability cutoffs in regulations from these nine states. Four states (Colorado, Montana, Texas, and Wyoming) have applicability thresholds in terms of VOC emissions. The remaining five states have storage vessel regulations that are in terms of tank characteristics, such as vapor pressure, tank size, or tank contents. Equivalency of applicability thresholds based on tank and stored liquid characteristics and applicability thresholds based on VOC emissions cannot be determined. We analyzed the varying state VOC emission thresholds (based on a range of 2 tpy to 25 tpy) as part of our cost of control analysis for VRUs and combustion devices in section 4.3.1 of this chapter.

Table 4-8. Summary of Storage Vessel Applicability Thresholds from Nine States

State/Local Authority	Applicability Threshold
Texas	Applies to storage vessels with VOC emissions greater than 25 tpy.
California Bay Area AQMD	Applies to storage vessels with capacity greater than 264 gallons.
California Feather River AQMD	Applies to storage vessels with capacity greater than 39,630 gallons.
California Monterey Bay Unified APCD	Applies to storage vessels with capacity greater than 39,630 gallons.

State/Local Authority	Applicability Threshold
California Sacramento Metropolitan AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
California San Joaquin Valley Unified APCD	Applies to storage vessels with capacity greater than 1,100 gallons.
California Santa Barbara County APCD	Applies to all storage vessels in tank battery (including wash tanks, produced water tanks, and wastewater tanks).
California South Coast AQMD	Applies to storage vessels with capacity greater than 39,630 gallons with a true vapor pressure of 0.5 psia or greater and storage vessels with a capacity greater than 19,815 gallons with a true vapor pressure of 1.5 psia or greater.
California Ventura County APCD	Applies to all storage vessels. Requirements depend on gallon capacity and true vapor pressure of material contained in vessel.
California Yolo-Solano AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
North Dakota	NDAC 33-15-07: submerged filling requirements to control VOC for tanks >1,000 gallons.
Federal Implementation Plan (FIP): Fort Berthold Indian Reservation	Applies to all storage vessels (except those covered by NSPS subpart OOOO). There is no minimum threshold under the final FIP.
Louisiana	Applies to storage vessels more than 250 gallons up to 40,000 gallons with a maximum true vapor pressure of 1.5 psia or greater.
Oklahoma	Applies to storage vessels with capacity greater than 40,000 gallons (in ozone nonattainment areas).
Wyoming – Statewide	Applies to storage vessels with greater than or equal to 10 tpy VOC within 60 days of startup/modification.
Wyoming – Concentrated Development Area	Applies to storage vessels with greater than or equal to 8 tpy VOC within 60 days of startup/modification.
Kansas	Permanent fixed roof storage tanks >40,000 gallons and external floating roof storage tanks.
Colorado	Condensate tanks with uncontrolled VOC emissions > 20 tpy (2 tpy located at gas processing plants in ozone non-attainment areas).

State/Local Authority	Applicability Threshold
Montana	Applies to oil or condensate storage tanks with a PTE greater than 15 tpy VOC.

4.4 Recommended RACT Level of Control

As discussed in section 4.3.2 of this chapter, existing federal and state and local regulations already require the reduction of VOC emissions from storage vessels in the oil and natural gas industry at or greater than 95 percent. Further, we note that combustion devices can be designed to meet 98 percent control efficiencies and can control, on average, emissions by 98 percent or more in practice when properly operated.[34] We also recognize that combustion devices designed to meet 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as the variability of field conditions. Therefore, the recommendations specify that devices should be required to continuously meet at least 95 percent VOC control efficiency. In light of the above considerations, a continuous 95 percent reduction of VOC emissions from storage vessels in the oil and natural gas industry is a reasonable recommended RACT level of control.

Although sources may have a choice on how they meet the recommended RACT level of control, if air agencies choose to adopt the recommended RACT contained in this CTG, the technologies that may be used to meet the recommended RACT level of control for oil and natural gas industry storage vessels are capturing and routing emissions to the process via a VRU and/or routing emissions to a combustion device.

As discussed in section 4.2.2 of this chapter, the VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility, and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric

[34] The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

pressure where it would not be cost-effective to require emission control requirements. Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Based on information gathered under the 2012 NSPS, [35] throughput and capacity of a storage vessel is not always the best indicator of a storage vessel's emissions, and we believe that the PTE of an individual storage vessel is preferable to use as an applicability threshold for storage vessels.

Based on our analyses conducted in support of the 2012 NSPS, 6 tpy was determined to be the applicability threshold for requiring 95 percent control of VOC emissions from new storage vessels (estimated to cost, on average, approximately $3,400 per ton of VOC reduced). Our analyses conducted for our RACT recommendation also found 6 tpy to be the applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels (estimated to cost, on average, between $4,400 and $5,000 per ton of VOC reduced). Based on these analyses, we recommend that the 95 percent VOC emission control of storage vessels only apply to storage vessels that have a PTE greater than or equal to 6 tpy of VOC emissions. The VOC cost of control per ton of VOC reduced would be less if a combustion device or VRU is used to control VOC emissions from multiple storage vessels because the cost for the additional storage vessels would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

We recommend an alternative RACT level of control for storage vessels that have a PTE VOC at or greater than 6 tpy that have actual emissions less than that on a continuing basis. For these storage vessels, if it can be demonstrated that the storage vessel has actual emissions less than 4 tpy for 12 consecutive months, we recommend that they be allowed to maintain and show continued compliance that their emissions are below 4 tpy in lieu of requiring 95 percent control. This alternative recommendation acknowledges that there are storage vessels that have a PTE greater than or equal to 6 tpy whose actual emissions have declined over time, usually because of declining production. This alternative RACT recommendation is informed by the 2012 NSPS, where we concluded that, based on "the cost-effectiveness, the secondary environmental impacts

[35] 77 FR 49490, August 16, 2012.

and the energy impacts…BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained (i.e., for 12 consecutive months) uncontrolled emission rates fall below 4 tpy."[36]

In summary, we recommend the following as RACT for storage vessels in the oil and natural gas industry:

(1) RACT for Condensate Storage Vessels: Reduce emissions by 95 percent continuously from condensate storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.[37]

(2) RACT for Crude Oil Storage Vessels: Reduce emissions by 95 percent continuously from crude oil storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.[38]

4.5 Factors to Consider in Developing Storage Vessel Compliance Procedures

4.5.1 Compliance Recommendations When Using a Control Device

Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emission control. We believe that such efforts on the part of owners and operators can result in more effective control of VOC emissions from storage vessels.

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a storage vessel when using a control device or other

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[36] Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards Final Amendments. Federal Register Notice. (78 FR 58429, September 23, 2013).

[37] We recommend that, prior to allowing the use of the uncontrolled 4 tpy actual VOC emissions rate for compliance purposes, air agencies require sources demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy for 12 consecutive months. After such demonstration, we recommend that air agencies require that sources demonstrate continued compliance with the uncontrolled actual VOC emission rate each month.

[38] See footnote 37.

control measure (such as routing to a process), the storage vessel should be equipped with a cover that is connected through a closed vent system that captures and routes emissions to the control device (or process). We recommend cover, closed vent system and control device design and compliance measures to ensure that control measures meet the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 4.5.1.1 and 4.5.1.2. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in sections 4.5.1.3 and 4.5.1.4. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

4.5.1.1 Recommendations for Cover Design

The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) should form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel. Each cover opening should be secured in a closed, sealed position (gasket lid or cap) whenever material is in the unit except when it is necessary to open as follows:

(1) To add material to or remove material from the unit (including openings necessary to equalize or balance the internal pressure of the unit following changes in the level of material in the unit);

(2) To inspect or sample the material in the unit;

(3) To inspect, maintain, repair, or replace equipment located in the unit; or

(4) To vent liquids, gases or fumes from the unit through a closed vent system designed and operated in accordance with specified closed vent system requirements (see section 4.5.1.2) or to a process.

It is recommended that air agencies require the storage vessel thief hatch be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated. It is recommended that air agencies require the gasket material for the hatch be selected based on composition of the fluid in the storage vessel and weather conditions.

It is also recommended that air agencies require monthly olfactory, visual and auditory inspections of covers for defects that could result in air emissions. Any detected defects should be required to be repaired as soon as practicable.

4.5.1.2 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (which can be monitored by monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, it is recommended that air agencies require owners and operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

4.5.1.3 Recommendations When “Routing to a Process” or to a VRU

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product and/or recovered. Vapor recovery units and flow lines that “route emissions to a process” would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 4.5.1.1 and 4.5.1.2 would apply.

4.5.1.4 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, it is recommended that air agencies require that the device operate at all times when gases, vapors, and fumes are vented from the storage vessel subject to VOC emission requirements through the closed vent system to the control device.

For control devices used to meet the recommended RACT, it is recommended that air agencies require owners and operators follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

If an owner or operator complies with the recommended RACT by using a combustion device, it is recommended that air agencies require initial and periodic performance testing (no later than 60 months after the initial performance test) to demonstrate initial and continued compliance with the recommended RACT level of control. Additionally, for each combustion device used to comply with the recommended continuous 95 percent VOC emission reduction, it is recommended that air agencies require owners and operators conduct the following control device compliance assurance measures: (1) Monthly visual inspections or monitoring to confirm that the pilot is lit when vapors are routed to it. (2) Monthly inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of part 60. It is recommended that the observation period be 15 minutes and that devices be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. (3) Monthly olfactory, visual and auditory inspections associated with the combustion device to ensure system integrity.

4.5.2 Compliance Recommendations When Complying with the 4 tpy VOC Emissions Alternative Limitation

If the alternative RACT recommendation to determine and maintain the uncontrolled actual VOC emissions from a storage vessel that has a PTE to emit greater than or equal to 6 tpy at less than 4 tpy without considering control is used, it is recommended that air agencies first require that a source demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, it is recommended that air agencies require that the source determine the uncontrolled actual VOC emission rate each month using a generally accepted model or calculation methodology. It is also recommended that such calculations be based on the average throughput for the month. If the monthly emissions determination indicates that VOC emissions from a storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, it is recommended that air agencies require that the source comply with the 95 percent VOC emission reduction RACT level of control recommendation or that emissions be routed to a VRU.

5.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the sources of VOC emissions from these compressors. This chapter also provides control techniques used to reduce VOC emissions from these compressors, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the associated VOC emission reductions and costs for both reciprocating and centrifugal compressors.

5.1 Applicability

For the purposes of this CTG, the emissions and emission reductions discussed herein would apply to centrifugal and reciprocating compressors in the oil and natural gas industry located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. As noted in section 3.2 of this document, we did not evaluate RACT for compressors located at a well site, or an adjacent well site and servicing more than one well site.

5.2 Process Description and Emission Sources

5.2.1 Process Description

5.2.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder. See Figure 5-1 for a depiction of a typical rod compressor packing system configuration.[39]

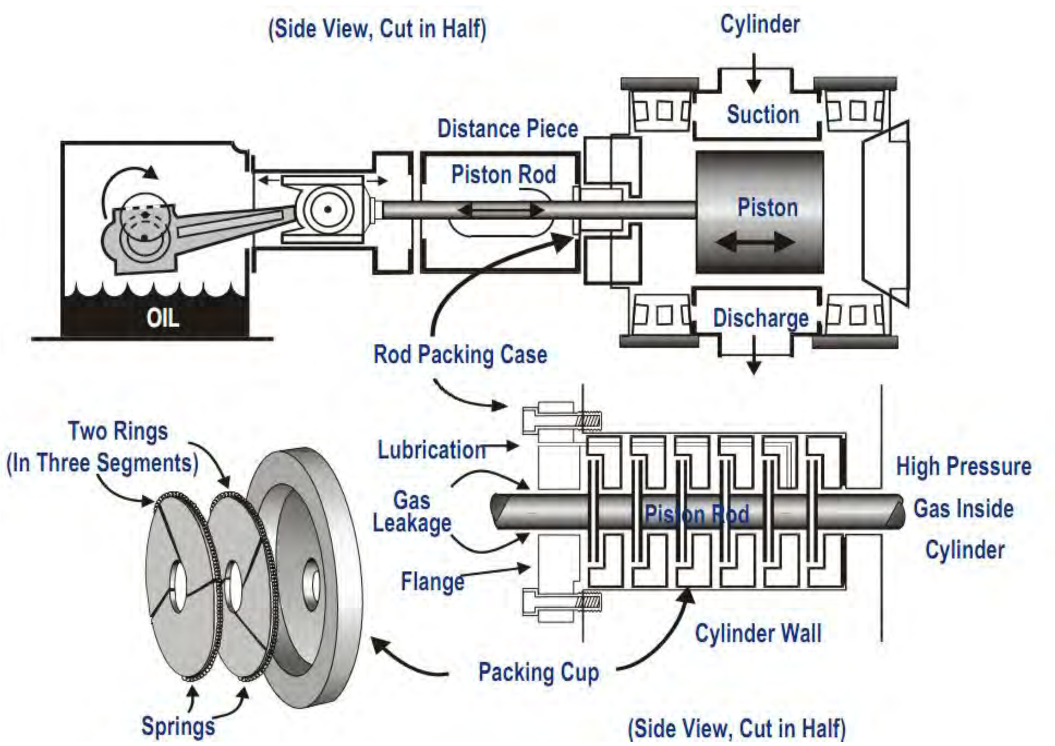

Figure 5-1. Typical Reciprocating Compressor Rod Packing System Diagram

5.2.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and

[39] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Figure 5-2 illustrates the wet seal compressor configuration.[40]

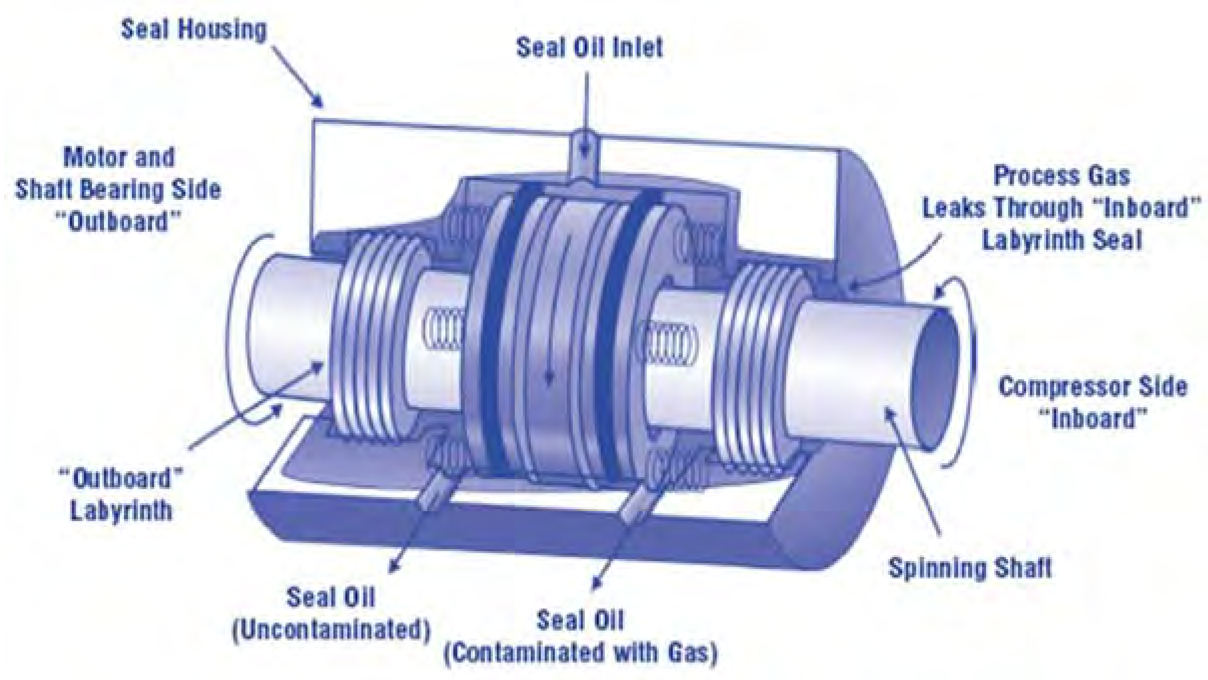

Figure 5-2. Typical Centrifugal Compressor Wet Seal

Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs (see Figure 5-3). The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed natural gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This natural gas is pumped between the grooves in the rotating and stationary rings. The opposing force of high-pressure natural gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little natural gas can leak. While the compressor is operating, the rings are not in

[40] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR Program. October 2006.

contact with each other and, therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.[41]

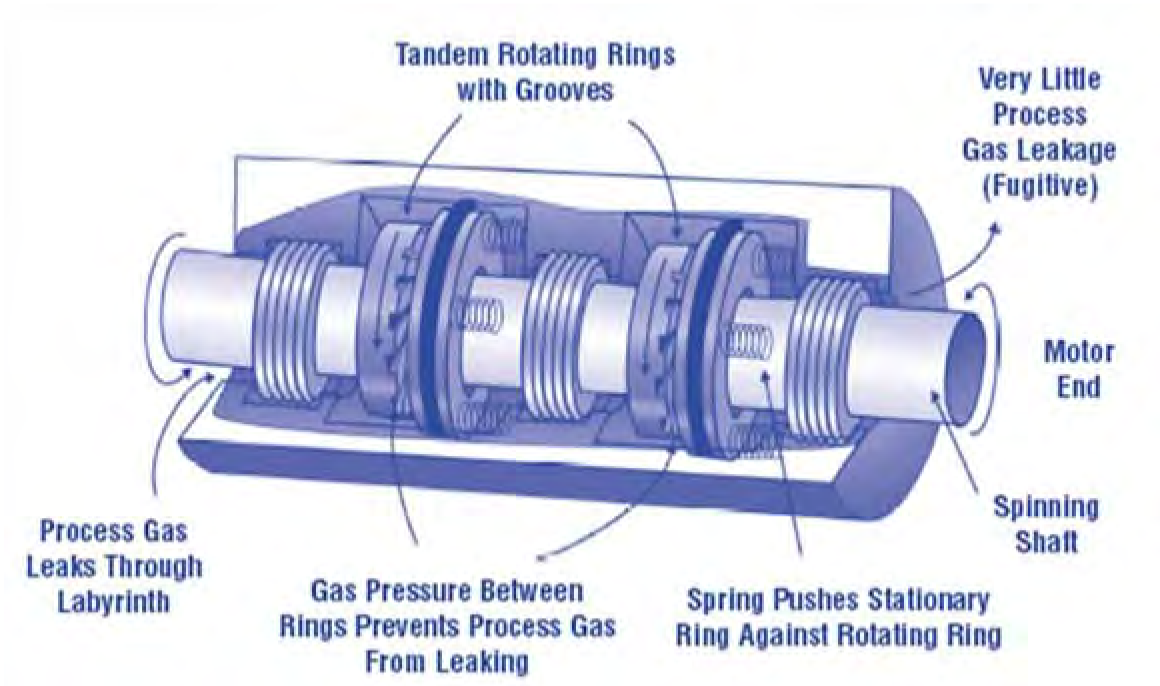

Figure 5-3. Typical Centrifugal Compressor Tandem Dry Seal

Natural gas emissions from wet seal centrifugal compressors have been found to be higher than dry seal compressors primarily due to the off-gassing of the entrained natural gas from the oil. This natural gas is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. In addition to lower natural gas leakage (and therefore lower emissions), dry seals have been found to have lower operation and maintenance costs than wet seal compressors because they are a mechanically simpler design, require less power to operate, and are more reliable. For the same reasons we explained in the 2012 NSPS and the 2015 NSPS proposal, we are not recommending RACT for dry seal compressors and instead include the use of a dry seal in place of a wet seal system as an available control option for reducing VOC emissions from wet seal centrifugal compressors (discussed in section 5.3.1.2 of this chapter). During the rulemakings for the 2012 NSPS and 2016 NSPS, we found that the dry seal system and the option of routing to a process both had at least a 95 percent control efficiency.

[41] Ibid.

5.2.2 Emissions Data

5.2.2.1 Summary of Major Studies and Emissions

Several studies have been conducted that provide leak estimates from reciprocating and centrifugal compressors. Table 5-1 lists these studies, along with the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Compressors."[42]

Table 5-1. Major Studies Reviewed for Emissions Data[43]

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[j]
Inventory of Greenhouse Gas Emissions and Sinks[a]	EPA	Annual	Nationwide	X	
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013)[b]	EPA	2014	Facility-Level	X	X
Methane Emissions from the Natural Gas Industry[c]	EPA/Gas Research Institute (GRI)	1996	Nationwide	X	
Natural Gas STAR Program[d,e]	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry Methane Emission Factor Improvement Study[f]	URS Corporation, UT Austin, and EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses[g]	API/ANGA	2012	Regional	X[h]	
Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[i]	ICF International (Prepared for the Environmental Defense Fund (EDF)	2014	Regional	X	X

[42] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Compressors. Report for Oil and Natural Gas Sector Compressors Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

[43] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[a] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[b] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.
[c] U.S. Environmental Protection Agency/GRI. National Risk Management Research Laboratory. Research and Development. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.
[d] U.S. Environmental Protection Agency. *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR. Environmental Protection Agency. 2006.
[e] U.S. Environmental Protection Agency. *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR. Environmental Protection Agency. October 2006.
[f] URS Corporation/University of Texas at Austin. 2011. *Natural Gas Industry Methane Emission Factor Improvement Study, Final Report*. December 2011. http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.
[g] American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA). *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses*. Final Report. September 21, 2012.
[h] The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emission information was included.
[i] ICF International. *Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries.* Prepared for the Environmental Defense Fund. March 2014.
[j] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

5.2.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The centrifugal compressor methane emission factors used for processing are based on emission factor data for wet seals and dry seals from a sampling of wet seal and dry seal centrifugal compressor data that was used to calculate emissions in the GHG Inventory.

For gathering and boosting station reciprocating compressors, the 2011 NSPS TSD emission factors were used because they are considered to be the best representative emission factors at this time. Emission factors in the Clearstone study,[44] which are expressed in thousand standard cubic feet per cylinder, were multiplied by the average number of cylinders per gathering and boosting station reciprocating compressor. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the reciprocating compressor methane

[44] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.

emission factors used for this analysis is presented in Table 5-2. Once the mass methane emission rate was calculated, ratios were used to estimate VOC emissions using the methane to VOC pollutant ratios developed in the 2011 Gas Composition Memorandum. The specific ratio that was used to convert methane emissions to VOC emissions is 0.278 pounds VOC per pound of methane for the production and processing segments. Table 5-3 presents a summary of the estimated methane and VOC emissions per reciprocating and centrifugal compressor (in tpy) for the production and processing segments.

Table 5-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors[45]

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scfh-cylinder)	Average Number of Cylinders	Pressurized Factor (Percent of Hours/Year Compressor Pressurized)	Wet Seal Methane Emission Factor (scfm)	Dry Seal Methane Emission Factor (scfm)
Gathering & Boosting Stations	25.9[a]	3.3	79.1%	N/A[c]	N/A[c]
Processing	57[b]	2.5	89.7%	47.7[d]	6[d]

[a] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.
[b] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks*. Table 4-14.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 11 – Compressor Driver Exhaust*. 1996 Report does not report any centrifugal compressors in the production or gathering/boosting segments, therefore no emission factor data were published for those two segments.
[d] U.S Environmental Protection Agency. *Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2012*. Washington, DC. April 2014.

[45] U.S. Environmental Protection Agency/GRI. Research and Development, National Risk Management Research Laboratory. *Methane Emissions from the Natural Gas Industry*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

Table 5-3. Baseline VOC Emission Estimates for Reciprocating and Centrifugal Compressors[a]

Industry Segment/Compressor Type	Baseline Emission Estimates (tpy)	
	Methane	VOC
Reciprocating Compressors		
Gathering and Boosting Stations	12.3	3.42
Processing	22	6.12
Centrifugal Compressors (Wet seals)		
Processing	210.53	19.1
Centrifugal Compressors (Dry seals)		
Processing	26	2.4

[a] For centrifugal compressors, it was assumed that 75 percent of the natural gas that is compressed is pipeline quality gas and 25 percent of the natural gas is production quality.

5.3 Available Controls and Regulatory Approaches

5.3.1 Available VOC Emission Control Options

Available controls for reducing VOC emissions from reciprocating and centrifugal compressors are presented in sections 5.3.1.1 and 5.3.1.2 of this chapter.

5.3.1.1 Reciprocating Compressors

Potential control options for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. These options include: (1) increasing or specifying the frequency of the replacement of the compressor rod packing, (2) increasing or specifying the frequency of the replacement of the piston rod, (3) specifying the refitting or realignment of the piston rod, and (4) routing of emission to a process through a closed vent system under negative pressure. In addition to these options, there are emerging control techniques where specific analyses have not yet been conducted. For example, there may be potential for reducing VOC emission by updating rod packing components made from newer materials which can help improve the life and performance of the rod packing system (economic rod packing replacement) and capturing gas from the reciprocating compressor and routing it back to the compressor engine to be used as fuel. These emerging VOC emissions control techniques are discussed briefly below, along with our evaluation of the frequency of compressor rod packing/piston rod replacement and piston rod refitting and realignment control options.

We do not believe that combustion is a technically feasible control option because, as detailed in the 2011 NSPS TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. While considering the option of routing of emissions to a process through a closed vent system under negative pressure, we determined that the negative pressure requirement not only ensures that all the emissions are conveyed to the process, it also avoids the issue of inducing back pressure on the rod packing and the resultant safety concerns. Although this option can be used in some circumstances, it cannot be applied in every installation. As a result, these options (i.e., routing of emissions to a control device, routing of emissions to a process through a closed vent system under negative pressure) were not further considered under this CTG.

Frequency of Rod Packing Replacement

For reciprocating compressors, one of the options for reducing VOC emissions is a maintenance task that would increase or specify the frequency of replacement of the rod packing in order to reduce the leakage of natural gas past the piston rod. Over time, the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces VOC emissions. Therefore, this control technique is considered to be an available VOC emission control technique for reciprocating compressors.

Description

As noted previously, reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed natural gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed natural gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod. [46]

[46] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

Control Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions for gathering and boosting stations and the processing segment were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing.

Based on industry information from the Natural Gas STAR Program, we have determined that the additional cost of shortening the replacement period more frequently than every three years or every 26,000 hours would not be justified based on the additional emission reductions that would be achieved.[47] Therefore, we analyzed emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every three years or every 26,000 hours. For the baseline, we assumed that rod packing is replaced every four years. The analysis uses Equation 1 for estimating gathering and boosting station emission reductions, and Equation 2 for estimating processing segment emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every 3 years or every 26,000 hours.[48]

Equation 1

$$R_{WP}^{G\&B} = \frac{Comp_{Existing}^{G\&B}\left(E_{G\&B} - E_{New}\right)\times C\times O\times 8760}{10^6}$$

Where:

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting stations by replacing worn packing with newly installed packing, in million cubic feet per year (MMcf/year);

$Comp_{Existing}^{G\&B}$ = Number of existing gathering and boosting station compressors;

$E_{G\&B}$ = Methane emission factor for gathering and boosting stations, in cubic feet per hour per cylinder (25.9 scfh-cylinder);

47 U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. 40 CFR Parts 60 and 63. Response to Public Comments on Proposed Rule*. August 23, 2011 (76 FR 52738). pg. 102.

48 U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[49] for this analysis;

C = Average number of cylinders for gathering and boosting stations (i.e., 3.3);

O = Percent of time during the calendar year the average gathering and boosting station is in the operating and standby pressurized modes, 79.1 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Equation 2 $$R_P = \frac{Comp^{P}_{Existing}\left(E_P - E_{New}\right)\times C \times O \times 8760}{10^6}$$

Where:

R_P = Potential methane emission reductions from processing compressors replacing worn packing to newly installed packing, in million cubic feet per year (MMcf/year);

$Comp^{P}_{Existing}$ = Number of existing processing compressors;

E_P = Methane emission factor for processing compressors, in cubic feet per hour per cylinder, 57 scfh-cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[50] for this analysis;

C = Average number of cylinders for processing compressors (i.e., 2.5);

O = Percent of time during the calendar year the average processing compressor is in the operating and standby pressurized modes, 89.7 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Table 5-4 presents a summary of the potential emission reductions for reciprocating compressor rod packing replacement for gathering and boosting stations and processing segment compressors based on the percent natural gas reduction calculated from the above equations. The emissions of VOC were estimated using the methane emissions calculated

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[49] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

[50] Ibid.

above and the methane-to-VOC ratio developed for each of the segments in the 2011 Gas Composition Memorandum.

Table 5-4. Estimated Annual Reciprocating Compressor Emission Reductions from Increasing the Frequency of Rod Packing Replacement

Oil and Natural Gas Segment	Individual Compressor Emission Reductions (tons/compressor-year)	
	Methane	VOC
Gathering and Boosting	6.84	1.9
Processing	17.58	4.89

Cost Impacts

Costs for the specified frequency of replacement of reciprocating compressor rod packing documented in the 2011 NSPS TSD were obtained from a Natural Gas STAR Lessons Learned document which estimated the cost to replace the packing rings to be $1,712 per cylinder (converted from 2008 dollars to 2012 dollars). It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and, therefore, no additional travel costs would be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing replacement is based on the number of hours that the compressor operates or the period of time since the previous replacement. The 2011 NSPS TSD analysis assumed that, at baseline, the replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. The cost impacts are based on the replacement frequency of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

The 26,000 hour replacement frequency used for the cost impacts in the 2011 NSPS TSD was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. Assuming an interest rate of 7 percent, the capital recovery factors (based on replacing the rod packing every 3 years or 26,000 hours) were calculated to be 0.3122 and 0.3490 for gathering and boosting stations and the processing segment, respectively. The capital costs were calculated using the average rod packing cost of $1,712 (converted from $1,620 in 2008 dollars to 2012 dollars) and the average number of cylinders per compressor (assumed to be 3.3 cylinders for gathering and boosting stations and 2.5 cylinders for processing segment compressors).[51] The annual costs were calculated using the capital costs and the capital recovery factors. Table 5-5 presents a summary of the capital and annual costs for gathering and boosting stations and the processing segment.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement. Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[52] Table 5-5 presents the annual costs with savings and cost of control for reciprocating rod packing replacement for gathering and boosting stations and the processing segment.

Reciprocating compressor rod packing replacement prevents the escape of natural gas from the piston rod. In addition to reducing VOC emissions, there would be a co-benefit of reducing other emissions (such as methane) as a result of increasing the frequency of rod packing replacement.

Table 5-5. Cost of Control for Increasing the Frequency of Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost ($2012)[a]	Annual Costs per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Gathering and Boosting	$5,650	$2,153	$566	$1,131	$298
Processing	$4,280	$1,631	($2,443)	$334	($500)

[a] 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent).

[51] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

[52] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price. U.S. Energy Information Administration Natural Gas Navigator*. Retrieved online on December 12, 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.

Frequency of Replacement and/or Realignment/Retrofitting of the Piston Rod

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[53] Rods wear "out-of-round" or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. We assume that operators will choose, at their discretion, when to replace/realign or retrofit the rod as part of regular maintenance procedures and replace the rod when appropriate when the compressor is out of service for other maintenance such as rod packing replacement. Therefore, we did not consider this option any further.

Updated Rod Packing Material

Although specific analyses have not been conducted, there may be potential for reducing VOC emissions by updating rod packing components made from newer materials, which can help improve the life and performance of the rod packing system. One option is to replace the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod.[54] Although changing the rod packing material has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry.

Economic Rod Packing Replacement

Another option facilities can use that has the potential to reduce costs and emissions is for facilities to use specific financial objectives and monitoring data to determine emission levels at which it is cost-effective to replace rings and rods. Benefits of calculating and utilizing this "economic replacement threshold" include VOC emission reductions and natural gas cost savings. Using this approach, one Natural Gas STAR partner reportedly achieved savings of over

[53] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.
[54] Ibid.

$233,000 annually at 2006 gas prices. An economic replacement threshold approach would also result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings.[55]

Gas Recovery (Routing of Emissions to a Process)

Description

Another control option for reciprocating compressors includes control techniques that recover natural gas leaking past the piston rod packing. We are aware of a system that captures the natural gas that would otherwise be vented and routes it back to the compressor engine to be used as fuel.[56] The vent gases are passed through a valve train that includes a demister and then are injected into the engine intake air after the air filter. In general, the technology consists of recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The system's computerized air/fuel control system would then adjust the normal fuel supply to accommodate the increased fuel made available from the recovered emissions and thereby take advantage of the recovered emissions while avoiding an overly rich fuel mixture.

Subpart OOOO, as well as subpart OOOOa, provide a compliance option for reciprocating compressors that allows collecting emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and routing the rod packing emissions to a process through a closed vent system. Both of the above systems, if installed using a cover and closed vent system meeting the subpart OOOO and subpart OOOOa requirements, could potentially be used for this compliance option.

Control Effectiveness

One estimate obtained by the EPA states that the gas recovery system can result in the elimination of over 99 percent of VOC emissions that would otherwise occur from the venting of the emissions from the compressor rod packing.[57] The emissions that would have been vented are combusted in the compressor engine to generate power.

[55] Ibid.
[56] REM Technology Inc. and Targa Resources. *Reducing Methane and VOC Emissions*. Presentation for the 2012 Natural Gas STAR Annual Implementation Workshop.
[57] REM Technology Inc., et al. *Profitable Use of Vented Emission in Oil & Gas Production*. Prepared with support from the Climate Change and Emissions Management Corporation (CCEMC). 2013.

If the facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95-100 percent of emissions. If the gas is routed to a flare, approximately 95 percent of the VOC emissions could be reduced.

Cost Impacts

One estimate reported that the cost per engine would be approximately $12,000 (does not include installation costs). Some costs would be mitigated by fuel gas savings, as using the captured gas to displace some of the purchased fuel would require less fuel to be purchased in order to run the compressor engine. The fuel cost saving based on a 4-throw compressor with moderate leak rate would be an estimated $6,500 per year.[58] This technique is discussed further in the Natural Gas STAR PRO Fact Sheet titled "Install Automated Air/Fuel Ratio Controls".[59] This document reported an average fuel gas savings of 78 Mcf/day per engine with the gas recovery system installed. Based on our review of information on this technology, we conclude that this technology has merit and would provide better emission reductions than increasing the replacement of rod packing from every 4 years to every 3 years since the emissions would be captured under negative pressure, allowing all emissions to be routed to the engine. It is our understanding that this technology may not be applicable to every compressor installation and situation.

For a VRU, assuming the proper equipment is already available at the facility, capturing the rod packing emissions would require minimal costs. The investment would only need to include the cost of piping and installation. While we have not obtained a cost estimate specifically for routing rod packing vents to a VRU, this process has been studied for dehydrators and would be similar for rod packing systems. According to the Natural Gas STAR PRO Fact Sheet titled "Pipe Glycol Dehydrator to Vapor Recovery Unit,"[60] the cost for planning and installing additional piping is approximately $2,000. Routing to a VRU also provides additional incentive as there is a value associated with recovered gas. However, the installation of a VRU to only capture rod packing emissions may not be economically viable if an additional compressor system is required. If the VRU is already present at the facility, the incremental cost

[58] REM Technology Inc. Presentation to the U.S. Environmental Protection Agency on December 1, 2011. EPA Docket ID No. EPA-HQ-OAR-2010-0505.
[59] U.S. Environmental Protection Agency. Gas STAR PRO No. 104. *Install Automated Air/Fuel Ratio Controls*. 2011.
[60] U.S. Environmental Protection Agency. Gas STAR PRO No. 203. *Pipe Glycol Dehydrator to Vapor Recovery Unit*. 2011.

to capture the rod packing vent gas can be recovered from the value of the additional captured natural gas.

Although gas recovery has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its availability as a reasonably available control option for reducing reciprocating compressor VOC emissions. However, we recommend that air agencies consider this technology as a compliance option when considering the RACT recommendations presented in section 5.4 of this chapter.

5.3.1.2 Centrifugal Compressors Equipped with Wet Seals

Potential control options to reduce emissions from centrifugal compressors equipped with wet seals include control techniques that limit the leaking of natural gas across the rotating shaft, and capture and destruction of the emissions by routing emissions to a process (e.g., a compressor or fuel gas system) or to a combustion device (discussed in detail in sections 4.3.1.2 of chapter 4). We evaluate below three available control options: (1) converting wet seals to dry seals, (2) routing emissions to a fuel gas system or compressor (process), and (3) routing emissions to a combustion device.

<u>Converting Wet Seals to Dry Seals</u>

Description

We evaluated the use of centrifugal compressor dry seals as an available VOC control option for wet seal centrifugal compressors. As noted in section 5.2 of this chapter, the VOC emission profile from the use of dry seals is considerably less than from the use of wet seals. Replacing wet seals with dry seals can, therefore, substantially reduce VOC emissions across the rotating shaft compared to wet seals, while simultaneously reducing operating costs and enhancing compressor efficiency compared to wet seals. During normal operation, dry seals leak at a rate of 6 scfm methane per compressor.[61] While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is recirculated is usually vented to the atmosphere,

[61] U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[62,63] It is not practical or feasible in all situations, however, to retrofit an existing wet seal compressor with a dry seal compressor. We have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission for the conversion period.

Control Effectiveness

The emission reductions that would occur by replacing wet seal compressors with a dry seal compressor were calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. We used the centrifugal compressor emission factors in Table 5-2 and estimated that VOC emissions would be reduced by 16.7 tpy per compressor.

Cost Impacts

The Natural Gas STAR Program estimated the cost of retrofitting dry seals on a centrifugal compressor equipped with wet seals to be $324,000 ($342,439 in 2012 dollars) for a two-seal dry seal system, which includes the cost of both seals and the dry gas conditioning, monitoring, control console and installation.[64] The annual costs were calculated as the capital recovery of the capital cost assuming a 20-year equipment life and 7 percent interest, which is approximately $32,324 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of a dry seal compressor is $88,300 ($93,325 in 2012 dollars) in comparison to a wet seal compressor. In addition, the installation of dry seals reduces natural gas emissions by 10,721 Mscf/yr[65] which results in an estimated natural gas savings of $42,883 per year assuming a natural gas price of $4/Mcf. A summary of the capital and annual costs for replacing a wet seal compressor with a dry seal compressor is presented in Table 5-6 along with the VOC cost of control. As noted above, we

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[62] U.S. Environmental Protection Agency, et al. *Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry*. World Gas Conference 10/2009.

[63] U.S Environmental Protection Agency. *Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems*. *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2012*. Washington, DC. Annex 3. Table A-129.

[64] U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

[65] The natural gas savings was calculated by using the 16.7 tpy VOC reduction and dividing by the VOC/methane weight ratio of 0.278 to determine the amount of methane reduction that would be reduced (60.1 tpy). The methane emission reductions were converted to volumetric natural gas reductions assuming a natural gas density of 0.02082 tons/Mcf and an 82.9 volume percent conversion factor of methane to natural gas.

have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission during the conversion period. Because of this, a facility may have to provide a temporary compressor in the interim that would add additional costs to the cost estimates we present in Table 5-6.

Table 5-6. Cost of Control of Replacing a Wet Seal Compressor with a Dry Seal Compressor

Oil & Natural Gas Segment	Capital Cost ($2012)	Annual Costs Per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings [a]	With O&M and Natural Gas Savings [b]	Without Savings	With O&M and Natural Gas Savings
Processing	$342,439	$32,324	($103,884)	$1,931	($6,205)

[a] Includes only the annualized capital cost of the retrofit of the dry seal system (20 years, 7 percent interest).
[b] Includes the annualized capital cost, annual operation and maintenance (O&M) savings and annual natural gas savings.

Routing Emissions to a Compressor or Fuel Gas System (Process)

Description

One option for reducing VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system or other beneficial use (referred to collectively as routing to a process). Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Emissions that are routed to a process can result in the same or greater emission reductions as would have been achieved had the emissions been routed through a closed vent system to a combustion device. Table 5-7 presents a summary of the estimated emission reductions from routing emissions from the wet seal fluid degassing system to a process. For purposes of this analysis, we assume that routing VOC emissions from a wet seal fluid degassing system to a process reduces VOC emissions greater than or equal to a combustion device (i.e., greater than or equal to 95 percent).

Table 5-7. Estimated Annual Centrifugal Compressor VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Process[66,67]

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	$\geq$ 18.1

Cost Impacts

The capital cost of a system to route the seal oil degassing system to a process is estimated to be $23,252,[68] converting to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[69] The estimated costs include an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The annual costs were estimated to be $2,553 assuming a 15-year equipment life at 7 percent interest.

Potential natural gas savings for this option were estimated to be 12 Mcf/yr and assumes that greater than or equal to 95 percent of the 47.7 scfm methane emissions are controlled, an annual operating factor of 43.6 percent, and the 82.9 volume percent conversion factor of methane to natural gas. Assuming a natural gas savings of $4/Mcf, the natural gas savings equates to approximately $47,553 per year. Table 5-8 presents a summary of the cost of control for routing emissions to a process.

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66 U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.
67 Ibid.
68 Ibid.
69 U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF]*, retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/GDPDEF/ March, 26, 2015.

Table 5-8. VOC Cost of Control for Routing Wet Seal Fluid Degassing System to a Process[a]

Oil and Gas Segment	Capital Cost ($2012)[a]	Annual Costs per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Processing	$23,252	$2,553	($47,553)	$141	($2,621)

[a] 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[70]

Routing Emissions to a Combustion Device

Description

Combustion devices are commonly used in the oil and natural gas industry to combust VOC emission streams. Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. Similar to the analysis of storage vessels, for this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of VOC. The wet seal emissions in Table 5-2 were used along with the control efficiency to calculate the emission reductions. Table 5-9 presents a summary of the estimated emission reductions from routing emissions from the wet seal to a combustion device.

Table 5-9. Estimated Annual VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Combustion Device[71]

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	18.1

[70] Ibid.
[71] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

Cost Impacts

Routing the captured gas from the centrifugal compressor wet seal degassing system to an existing combustion device or installing a new combustion device has associated capital and operating costs. The capital and annual costs of the combustion device (an enclosed flare for the analysis) were calculated using the methodology in the EPA Control Cost Manual.[72] The heat content of the gas stream was calculated using information from the 2011 Gas Composition Memorandum. Table 5-10 presents a summary of the capital and annual costs for wet seals routed to a flare, as well as the VOC cost of control. There is no cost savings estimated for this option because the recovered natural gas is combusted.

Table 5-10. Cost of Control for Routing Wet Seal Fluid Degassing System to a Combustion Device

Industry Segment	Capital Cost ($)		Annual Cost per Compressor ($/compressor-year)		VOC Cost of Control New CD ($/ton)	VOC Cost of Control Existing CD ($/ton)
	New CD	Existing CD	New CD	Existing CD		
Processing	$71,783	$23,252	$114,146	$3,311	$6,292	$183

CD = Control Device

5.3.2 Existing Federal, State and Local Regulations

5.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, reciprocating compressors are required to limit VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the previous rod packing replacement. Alternatively, an owner or operator is allowed to route rod packing emissions to a process through a closed vent system under negative pressure. For centrifugal compressors in the processing segment, the 2012 NSPS and 2016 NSPS require that VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95 percent.

[72] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

5.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

Montana requires oil and natural gas well facilities to control emissions from the time the well is completed until the source is registered or permitted. Each piece of oil or natural gas well facility equipment, with VOC vapors of 200 Btu/scf or more with a PTE greater than 15 tpy, is required to (1) capture and route emissions to a natural gas pipeline, (2) route to a smokeless combustion device equipped with an electronic ignition device or a continuous burning pilot system meeting the requirements of 40 CFR 60.18 and operating at 95 percent or greater control efficiency, or (3) route to air pollution control equipment with equal or greater control efficiency than a smokeless combustion device. This includes the control of emissions from compressor engines used for transmission of natural gas (Registration of Air Contaminant Sources, Rule 17.8.1711 Oil or Gas Well Facilities Emission Control Requirements).

Colorado (Regulation 7, XVII.B.3.b and c) requires that uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors be controlled by at least 95 percent, unless the centrifugal compressor is subject to 40 CFR part 60, subpart OOOO. Additionally, Regulation 7 requires that rod packing on any reciprocating compressor located at a natural gas compressor station be replaced every 26,000 hours of operation or every 36 months, unless the reciprocating compressor is subject to 40 CFR part 60, subpart OOOO.

5.4 Recommended RACT Level of Control

For reciprocating compressors, there are federal and state regulations that require the periodic replacement of reciprocating compressor packing. The federal regulations (the 2012 NSPS and 2016 NSPS) require the replacement of reciprocating compressor rod packing every 3 years or on or before 26,000 hours of operation. The state regulation (Colorado) requires the replacement of reciprocating compressor rod packing every 26,000 hours of operation or every 36 months. The 2012 NSPS and 2016 NSPS also provide the alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

As noted in section 5.3 of this chapter, the most significant volume of VOC emissions are associated with piston rod packing systems. We found that, under the best conditions, regular rod packing replacement, when carried out approximately every three years, effectively controls emissions and helps prevent excessive rod wear. The cost of control for requiring the replacement of reciprocating packing at this frequency was estimated to be $1,132 per ton of VOC reduced without savings and $298 per ton of VOC reduced considering savings for gathering and boosting station compressors, and about $334 per ton of VOC reduced without savings, and an overall net savings per ton of VOC reduced for processing segment reciprocating compressors considering savings. Based on the emission reductions, costs (considering gas savings) and existing and currently implemented regulations that require the replacement of the reciprocating compressor packing every 36 months or on or before 26,000 hours of operation, we recommend this control option as RACT for reciprocating compressors in the production and processing segments (excluding compressors at the well site). We also recommend that air agencies provide operators the compliance alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

For centrifugal compressors, there are already federal, state and local regulations that require the capture and 95 percent control of emissions from wet seal fluid degassing systems from centrifugal compressors. Although dry seal systems have low VOC emissions and the option of routing to a process has at least a 95 percent control efficiency, the replacement of wet seals with dry seals and routing to a process may not be technically feasible or practical options for some centrifugal compressors. The integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, and, in the case of capture of emissions with routing to a process, there may not be downstream equipment capable of handling a low-pressure fuel source. As a result of our evaluation of the technical feasibility and practicality of existing available controls, we recommend RACT be 95 percent control of emissions from the wet seal degassing system, which can be achieved by using a closed vent system and routing emissions to a combustor or routing the emissions back to the compressor or fuel line (routing to the process). For the processing segment, we assume that there is an existing combustion device onsite and the estimated cost of control would be about \$183 per ton of VOC reduced for facilities to route emissions to the existing combustion device, or about \$141 per ton of VOC reduced for facilities to route the captured emissions back to the compressor or fuel line.

In summary, we recommend the following as RACT for compressors:

(1) <u>RACT for Reciprocating Compressors Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site):</u> We recommend that each reciprocating compressor reduce VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the last rod packing replacement. We also recommend that an alternative be provided to allow routing of rod packing emissions to a process via a closed vent system under negative pressure in lieu of the specified rod packing replacement periods. We do not recommend that RACT apply to individual reciprocating compressors located at a well site, or an adjacent well site and servicing more than one well site.

(2) <u>RACT for Centrifugal Compressors Using Wet Seals Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site):</u> We recommend that each centrifugal compressor using wet seals reduce VOC emissions from each wet seal fluid gassing system by reducing VOC emissions by 95 percent. We do not recommend that RACT apply to individual centrifugal compressors using wet seals located at a well site, or an adjacent well site and servicing more than one well site.

5.5 Factors to Consider in Developing Compressor Compliance Procedures

5.5.1 Reciprocating Compressor Compliance Recommendations

In order to ensure and demonstrate compliance with the recommended RACT for reciprocating compressors, we recommend that air agencies require facilities to maintain a record of the date of the most recent reciprocating compressor rod packing replacement, monitor and keep records of the number of hours of operation and/or track the number of months since the last rod packing replacement for each reciprocating compressor (to meet the requirement that the packing is changed out on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months) and maintain records of instances where the reciprocating compressor was not operated in compliance with RACT. This may require the installation of an operating hours meter on the engine to track the number of hours of operation. We also recommend that air agencies require annual reports of the cumulative hours of operation or number of months since packing replacement for each reciprocating compressor and instances when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT.

For applications in which operators choose to opt for the alternative of routing of rod packing emissions to a process via a closed vent system under negative pressure, it is recommended that air agencies require facilities to maintain records of the date of installation of a rod packing emissions collection system and closed vent system and maintain records of instances of deviations in cases where the reciprocating compressor was not operated in compliance with requirements. We also recommend that air agencies require annual reports for each reciprocating compressor complying with this option indicating when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4.

The appendix to this document presents example model rule language that incorporates compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.2 Centrifugal Compressor Equipped with a Wet Seal Recommendations

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a centrifugal compressor equipped with a wet seal when using a control device or other control measure (such as routing to a process), the centrifugal compressor should be equipped with a cover that is connected through a closed vent system that routes emissions to the control device (or process) that meets the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in section 5.5.5.

The appendix of this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.3 Recommendations for Cover Design

The cover and all openings on the cover should form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system (for centrifugal compressors), and of the rod packing emissions collection system (for reciprocating compressors). Each cover opening should be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(1) To inspect, maintain, repair, or replace equipment; or

(2) To vent gases or fumes from the unit, through a closed vent system designed and operated in accordance with closed vent system requirements (see section 5.5.4), to a control device or to a process.

It is recommended that air agencies require olfactory, visual and auditory inspections of covers for defects that could result in air emissions on a monthly basis. We recommend air agencies require that any detected defects be repaired as soon as practicable.

5.5.4 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of Part 60, and ongoing monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open

such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

5.5.5 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, we advise that the device be required to operate at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. The following paragraphs present select emission control options and suggested operation and monitoring requirements, as appropriate to ensure compliance with the recommended RACT level of control.

Enclosed Combustion Devices

If an enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) is used to meet the 95 percent VOC emission reduction RACT level of control, it should be designed to reduce the mass content of VOC emissions by 95 percent or greater and be: (1) maintained in a leak free condition, (2) installed and operated with a continuous burning pilot flame, and (3) operated with no visible emissions.

It is recommended that the visible emissions test (using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7) be performed at least once every calendar month. If a combustion device fails the visible emissions test, sources should be required to follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. It is recommended that all inspection, repair and maintenance activities for each unit be recorded in a maintenance and repair log that can be made available for inspection. Following return to operation from maintenance or repair activity, each device should be required to pass a Method 22, 40 CFR part 60, appendix A-7 visual emissions test.

It is recommended that air agencies require that sources meeting the 95 percent VOC emission reduction RACT level of control by routing emissions to a combustion device conduct performance tests and/or design analyses that demonstrate that the combustion device being used meets the required 95 percent VOC emission reduction RACT level of control (see section F of the appendix to this document for performance testing procedures for control devices that we recommend be used to demonstrate performance requirements).

Routing to a Process

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Vapor recovery units and flow lines that "route emissions to a process" would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 5.5.3 and 5.5.4 would apply.

6.0 PNEUMATIC CONTROLLERS

The oil and natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic, (2) electrical, or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are pneumatic devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves and may be actuated using pressurized natural gas (natural gas-driven) or may be actuated by another means such as a pressurized gas other than natural gas, solar, or electric. This chapter describes pneumatic controllers that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also presents control techniques used to reduce VOC emissions from these pneumatic controllers, along with costs and emission reductions. Finally, this chapter discusses our recommended RACT and the associated VOC emission reductions and costs for pneumatic controllers.

6.1 Applicability

For the purposes of this CTG, a pneumatic controller is an automated instrument used to maintain a process condition such as liquid level, pressure, pressure differential and temperature. The emissions and emission controls discussed herein would apply to natural gas-driven pneumatic controllers in the oil and natural gas industry located from the wellhead to a natural gas processing plant (including the natural gas processing plant) or from the wellhead to the point of custody transfer to an oil pipeline.

6.2 Process Description and Emission Sources

6.2.1 Process Description[73]

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this CTG, they are characterized primarily by their emission characteristics:

(1) *Continuous bleed pneumatic controllers* are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time. Continuous bleed controllers are further subdivided into two types based on their bleed rate:

   a. *Low-bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).

   b. *High-bleed*, having a bleed rate of greater than 6 scfh.

(2) *Intermittent bleed or snap-acting pneumatic controllers* release gas only when they open or close a valve or as they throttle the gas flow.

(3) *Zero-bleed pneumatic controllers* do not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Pneumatic controllers often make use of available high-pressure natural gas to operate or control a valve. The supply gas pressure is modulated by a process condition, and then flows to the valve controller where the signal is compared with the process set point to adjust gas pressure in the valve actuator. In these natural gas-driven pneumatic controllers, natural gas may be released intermittently with every actuation of the valve. In other designs, natural gas may be released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady state rates when operated under similar conditions. It is our understanding that self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. “Closed loop” systems are applicable only in instances with very low pressure[74] and may not be suitable to

[73] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[74] Memorandum to Bruce Moore, U.S. Environmental Protection Agency, from Denise Grubert, EC/R Incorporated. *Meeting Minutes from EPA Meeting with the American Petroleum Institute (API)*. October 2010.

replace many applications of continuous or intermittent bleed pneumatic devices. Therefore, this CTG does not address these self-contained devices further.

Intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the controller's bleed stream. Since actuation emissions serve the controller's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 6.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation. Intermittent controllers are assumed to have zero bleed emissions. For most applications (but not all), intermittent controllers serve functionally different purposes than bleed devices. Therefore, because the total emissions are dependent on the application in which they are used, we do not consider their use to be a technically practical control option for all continuous bleed controllers.

As previously indicated, not all pneumatic controllers are natural gas driven. At sites with a continuous and reliable source of electricity, controllers can be actuated by an instrument air system that uses compressed air instead of natural gas. These sites may also use mechanical or electrically powered pneumatic controllers. In some instances, solar-powered controllers may be feasible. Because these devices are not natural gas driven, they do not directly release natural gas or VOC. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. To our knowledge, natural gas processing plants are the only facilities in the oil and natural gas industry that are likely to have electrical service sufficient to power an instrument air system, and most existing natural gas processing plants use instrument air instead of natural gas-driven devices.[75]

[75] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R/-96-080k. June 1996.

6.2.2 Emissions Data

6.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic controllers and the potential options available to reduce VOC emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."[76]

Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[l]
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013)[a]	EPA	2014	Facility-Level	X	X
Inventory of Greenhouse Gas Emissions and Sinks[b]	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry[c]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry[d]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the U.S. Oil Industry[e]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[f]	WRAP	2005	Regional	X	
Natural Gas STAR Program[g]	EPA	2000 – 2010	Voluntary	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States[h]	Multiple Affiliations, Academic and Private	2013	Nationwide	X	

[76] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel.* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[l]
Determining Bleed Rates for Pneumatic Devices in British Columbia[i]	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas[j]	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[k]	ICF International	2014	Nationwide	X	X

[a] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC.
[b] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report.* EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.
[d] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry. Draft Report*. June 14, 1996.
[e] ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.
[f] ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States.* Prepared for Western Governors Association. December 27, 2005.
[g] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[h] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.
[i] U.S. Environmental Protection Agency. *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas Star. Washington, DC. 2006.
[j] U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.
[k] Canadian Environmental Technology Advancement Corporation (CETAC)-WEST. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments.* Prepared for the Canadian Association of Petroleum Producers. May 2008.

[1] An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

6.2.2.2 Representative Pneumatic Controller Device Emissions

For purposes of this CTG, continuous bleed pneumatic controllers are classified into two types based on their emissions rates: (1) high-bleed controllers, and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 scfh, while low-bleed devices bleed at a rate less than or equal to 6 scfh.[77]

In support of the development of the 2012 NSPS and 2016 NSPS, and this CTG, we consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, subpart W of the GHGRP, the GHG Inventory, as well as pneumatic controller vendor information used during the development of the 2012 NSPS.[78] The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic controller model (or model family). All pneumatic controllers that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although, by definition, a low-bleed device can emit up to 6 scfh, through vendor research, a typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have bleed rates from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high-bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[79,80] While the vendor data provided useful information on specific makes and models, it did not yield sufficient information about the prevalence of each model type in the population of devices in the oil and

[77] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled “Unaccounted for Gas Project Summary Volume.” This classification was adopted for the October 1993 Report to Congress titled “Opportunities to Reduce Anthropogenic Methane Emissions in the United States”. As described on page 2-16 of the report, “devices with emissions or ‘bleed rates’ of 0.1 to 0.5 cubic feet per minute are considered to be ‘high-bleed’ types (PG&E 1990).” This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[78] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

[79] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2010.

[80] All rates are listed at an assumed supply gas pressure of 20 psig.

natural industry, which is an important factor in developing a representative emission factor. Therefore, in support of this CTG, we have determined that the best available emission estimates for pneumatic controllers in the production segment are from the GHGRP. For the natural gas processing segment, we determined that the quantified representative methane emissions from a continuous bleed pneumatic controller based on natural gas emission rates presented in Volume 12 of the EPA/GRI report used in the 2012 NSPS TSD is the best available emissions information.[81]

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from an average high-bleed and low-bleed pneumatic controller in the production and processing segments and then estimate methane and VOC emissions using a representative gas composition from the 2011 Gas Composition Memorandum. A bleed rate of 1.39 scfh was used for a low-bleed controller, and a bleed rate of 37.3 scfh was used for a high-bleed controller. The specific gas composition ratio used for the production and processing segments was 0.278 pounds VOC per pound methane. Table 6-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment (for production and processing segments) and device type.

Table 6-2. Average Emission Rates for High-Bleed and Low-Bleed Pneumatic Controllers in the Oil and Natural Gas Industry[a]

Industry Segment	High-Bleed (tpy)		Low-Bleed (tpy)	
	Methane	VOC	Methane	VOC
Oil and Natural Gas Production[b,c]	5.3	1.47	0.2	0.06
Natural Gas Processing[d]	1.00	0.28	1.0	0.28

[a] The conversion factor used in this analysis is 1 Mcf of methane is equal to 0.0208 tons methane.
[b] Natural gas production methane emissions are derived from the GHGRP (subpart W).
[c] Oil production methane emissions are derived from the GHGRP (subpart W). It is assumed only continuous bleed devices are used in oil production.
[d] Natural gas processing segment methane emissions are derived from Volume 12 of the 1996 EPA/GRI report. Emissions from devices in the processing segment were determined based on data available for snap-acting and continuous bleed devices. Further distinction between high-

[81] GRI/EPA Research and Development. Methane Emissions from the Natural Gas Industry; Volume 12: Pneumatic Devices. (1996) EPA-600/R-96-0801. Table 4-11, page 56.

and low-bleed could not be determined based on available data. For the natural gas processing segment, it is assumed that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

6.3 Available Controls and Regulatory Approaches

6.3.1 Available VOC Emission Control Options

Although pneumatic controllers have relatively small emissions individually, due to the large population of these devices, the cumulative VOC emissions for the industry are significant. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic controllers. The following sections provide a summary of options for reducing VOC emissions from pneumatic controllers including: (1) replacing high-bleed controllers with low-bleed controllers or zero-bleed controllers; (2) driving controllers with instrument air rather than natural gas, using non-gas-driven controllers; and (3) enhanced maintenance.

Sections 6.3.1.1 and 6.3.1.2 discuss the control of VOC emissions by replacing a high-bleed device with a low-bleed device, and driving controllers with instrument air rather than natural gas, including the estimated costs of these options. Given applicability, efficiency and the expected costs, other options (i.e., mechanical controls and enhanced maintenance) are only briefly discussed in sections 6.3.1.3 and 6.3.1.4.

6.3.1.1 Install a Low-Bleed Device in Place of a High-Bleed Device

<u>Description</u>

As discussed previously, low-bleed controllers generally provide the same operational function as a high-bleed controller, but have lower continuous bleed emissions.

<u>Control Effectiveness</u>

We estimate on average that 1.41 tons of VOC will be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device. There are certain situations in which replacing and retrofitting devices are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high-bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, we assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production segment.

Applicability of low-bleed controllers may depend on the function carried out by the controller. Low-bleed pneumatic controllers may not be applicable for replacement of high-bleed devices because a process condition may require a fast or precise control response to minimize deviation from the desired set point. A slower acting low-bleed controller could potentially result in damage to equipment and/or become a safety issue because it may not be able to respond as quickly as a high-bleed controller. An example of this is a compressor where pneumatic controllers may monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady state) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can typically accommodate control from a low-bleed device, which is slower acting and less precise.

Cost Impacts

Costs were based on vendor research as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers.[82] As Table 6-3 indicates, the average cost for a low-bleed pneumatic controller is $2,698, while the average cost for a high-bleed pneumatic controller is $2,471.[83] In order to analyze cost impacts, the average cost to install a new low-bleed pneumatic controller was annualized for a 15-year period using a 7 percent interest rate. This equates to an annualized cost of around $271 per low-bleed device for the production segment.

[82] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners*. Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry***.** Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[83] Costs are estimated in 2012 U.S. dollars.

Table 6-3. Cost Projections for Representative Pneumatic Controllers[a]

Device	Minimum Cost ($2012)	Maximum Cost ($2012)	Average Cost ($2012)
High-Bleed Controller	$387	$7,398	$2,471
Low-Bleed Controller	$554	$9,356	$2,698

[a] 201l NSPS TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent). During the development of the 2012 NSPS, major pneumatic controller vendors were surveyed for costs, emission rates and any other pertinent information.

Monetary savings associated with retaining natural gas that would have been emitted was estimated based on a natural gas value of $4.00 per Mcf.[84] The use of a low-bleed pneumatic controller is estimated to reduce methane emissions by 5.1 tpy (245 Mcf/yr) (using the conversion factor of 0.0208 tons methane per 1 Mcf) over the use of a high-bleed pneumatic controller. Assuming natural gas in the production segment is 82.8 percent methane by volume, this equals 296 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic controller in the production segment is approximately $1,184. Table 6-4 presents the estimated cost of control per ton of VOC reduced for replacing a high-bleed pneumatic controller with a new low-bleed pneumatic controller in the production segment of the oil and natural gas industry.

Table 6-4. VOC Cost of Control for Replacing an Existing High-Bleed Pneumatic Controller with a New Low-Bleed Pneumatic Controller

Segment	Average Capital Cost per Unit ($2012)[a,c]	Total Annual Costs per Unit ($2012/yr)[b,c]		VOC Cost of Control ($2012/ton)[c]	
		Without Savings	With Savings	Without Savings	With Savings
Oil and Natural Gas Production	$2,698	$296	($886)	$209	($625)

[a] Average capital cost of a low-bleed device as summarized in Table 6-3.
[b] Annualized cost assume a 7 percent interest rate over a 15-year equipment lifetime.
[c] Cost data from the 2011 TSD converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent).

[84] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price. U.S. Energy Information Administration. Natural Gas Navigator*. Retrieved online on 12 Dec 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.

6.3.1.2 Instrument Air Systems

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator and volume tank. The following is a description of each component as described in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air":[85]

(1) Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

(2) A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, natural gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be cost-effective for remote locations, and reduce both VOC emissions and energy consumption. Small natural gas-driven fuel cells are also being developed.

(3) Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

[85] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006.

(4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. The use of instrument air eliminates natural gas emissions from natural gas-driven pneumatic controllers. All other parts of a natural gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available. Figure 6-1 illustrates a diagram of a natural gas pneumatic control system. Figure 6-2 illustrates a diagram of a compressed instrument air control system. [86]

Control Effectiveness

The use of instrument air eliminates natural gas emissions from the pneumatic controllers; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is access to high Btu gas, a high concentration of pneumatic control valves and the presence of an operator who can ensure the system is properly functioning.[87]

For natural gas processing plants, we believe that instrument air systems are typically used to power pneumatic controllers and that any natural gas-driven pneumatic controllers in use are required for safety and functional reasons. The use of an instrument air system would reduce VOC emissions from a natural gas-driven pneumatic controller by 100 percent.

Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressurized air. The size of the compressor depends on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas

[86] Ibid.
[87] Ibid.

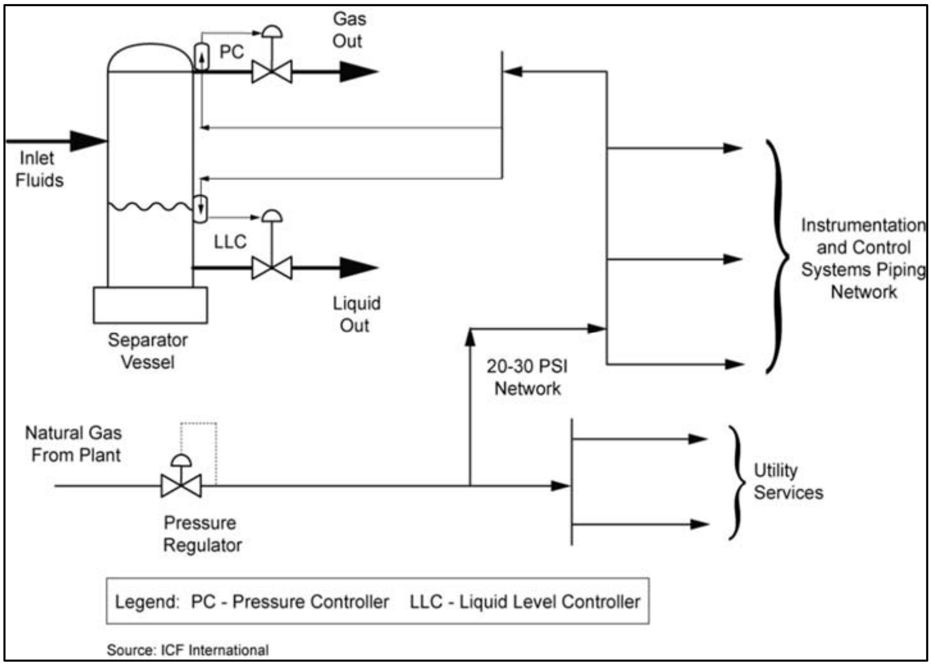

Figure 6-1. Natural Gas Pneumatic Control System

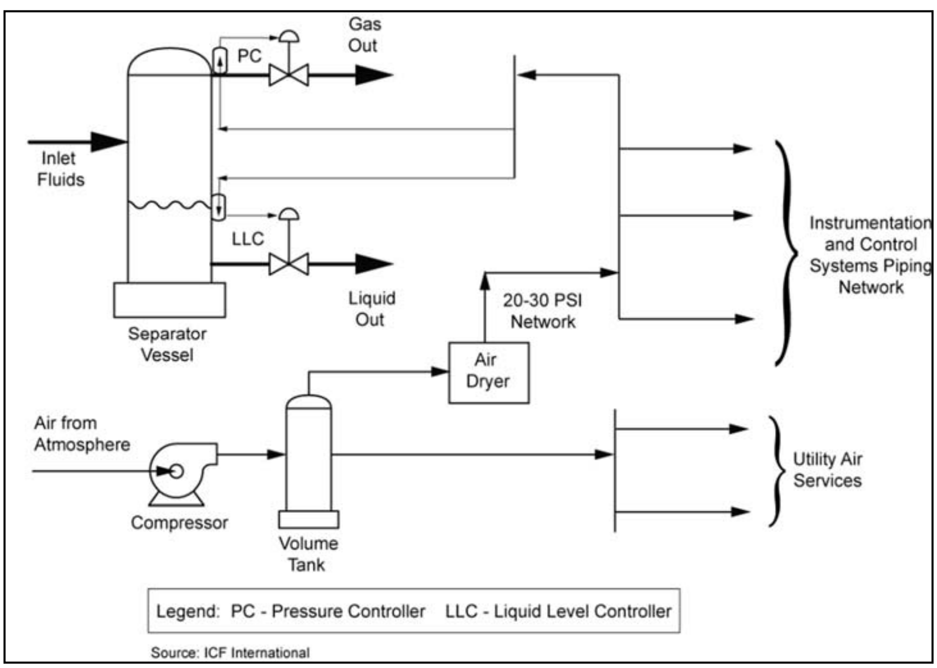

Figure 6-2. Compressed Instrument Air Control System

used to run the existing instrumentation, adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power and a backup system to operate the controllers in the event of interruption of the electrical supply. Table 6-5 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 6-5. Compressor Power Requirements and Costs for Representative Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate (cfm)	Control Loops (Loops/Compressor)	Power Costs ($/yr)
Size of Unit	Hp	kW			
Small	10	13.3	30	15	$7,758
Medium	30	40	125	63	$23,332
Large	75	100	350	175	$58,329

[a] Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air.* Natural Gas STAR Program. Washington, DC. 2006.
[b] Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and the related equipment and operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator, gas supply piping, control instruments, valve actuators and a storage vessel. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air” and are summarized in Table 6-6.[88]

[88] Ibid.

Table 6-6. Estimated Capital and Annual Costs of Representative Instrument Air Systems ($2012)

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital Cost[a]	Annualized Capital Cost[b]	Labor Cost	Total Annual Cost[c]	Annualized Cost of Instrument Air System
Small	$3,987	$797	$2,391	$17,938	$2,554	$1,410	$9,168	$11,722
Medium	$19,928	$2,391	$7,173	$77,716	$11,065	$4,580	$27,912	$38,977
Large	$35,071	$4,783	$15,941	$143,476	$20,428	$6,340	$64,669	$85,097

[a] Total Capital Cost includes the cost for two compressors, two tanks, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the 2012 NSPS TSD.
[b] These costs have been converted to 2012 dollars (from 2008 dollars) using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent).[89]
[c] The annualized cost was estimated using a 7 percent interest rate and 10-year equipment life. Annual cost includes the cost of electrical power, as listed in Table 6-5, and labor.

[89] U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF]*, retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/GDPDEF/ March, 26, 2015.

For new natural gas processing plants, the cost-effectiveness of the three representative instrument air system sizes was evaluated in the 2015 NSPS Proposal TSD based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems. For existing natural gas processing plants, it is our understanding that these plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. The cost of converting the pneumatic controllers to instrument air includes the capital cost of $2,000 for the ductwork and annual cost of $285 (assuming a 10-year equipment life at 7 percent interest). The VOC cost of control for converting pneumatic controllers to instrument air for processing plants that already have instrument air ranges from $6 to $68 per ton of VOC removed, depending on the size of the instrument air system.

For natural gas processing, the cost of control of the three representative instrument air systems was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per controller basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems.

Table 6-7. Cost of Control of Representative Instrument Air Systems in the Natural Gas Processing Segment ($2012)

System Size	Number of Control Loops	VOC Annual Emission Reduction (tpy)[a]	Value of Product Recovered ($2012/year)[b]	Annualized Cost of System		VOC Cost of Control ($2012/ton)	
				Without Savings	With Savings	Without Savings	With Savings
Small	15	4.18	$3,485	$11,722	$8,236	$2,804	$1,970
Medium	63	17.5	$14,592	$38,977	$24,385	$2,227	$1,393
Large	175	48.7	$40,606	$85,097	$44,490	$1,747	$914

[a] Based on the emissions mitigated from the entire system, which includes multiple control loops.
[b] Value of recovered product assumes natural gas processing is 82.9 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

6.3.1.3 Electrically Powered Systems in Place of Bleed Devices

Description

Mechanical controls have been widely used in the oil and natural gas industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages.[90] Another device that is increasing in use is electrically powered controls. Small electrical motors (including solar powered) have been used to operate valves and have no VOC emissions. Solar-powered control systems are driven by solar-power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Control Effectiveness[91]

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems may have difficulty handling larger flow fluctuations. Electrically powered valves are only reliable with a constant supply of electricity. These controllers can achieve a 100 percent reduction in VOC emissions where applicable.

Cost Impacts

Depending on supply of power, mechanical and solar-power system costs can range from below $1,000 to $10,000 for an entire system.[92]

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[90] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[91] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[92] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

6.3.1.4 Enhanced Maintenance of Natural Gas-Driven Pneumatic Controllers

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age and wear of the device.[93] Examples of circumstances or factors that can contribute to this increase include:[94,95]

(1) Nozzle corrosion resulting in more flow through a larger opening;
(2) Broken or worn diaphragms, springs (e.g., spring broken that holds the supply pilot plug on its seat), bellows, fittings (e.g., leaking tubing/tubing-fittings) and nozzles;
(3) Corrosives in the gas leading to erosion and corrosion of control loop internals;
(4) Improper installation;
(5) Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals);
(6) Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle;
(7) Foreign material lodged in the pilot seat;
(8) Debris/deposits on vent pilot plug. Material on the vent pilot can allow the controller to exhaust gas during the activation cycle;
(9) Debris/deposits on the supply pilot plug. Material on the supply pilot can cause the introduction of gas while the vent is open; or
(10) Wear in the seal seat.

The EPA prepared a white paper titled “Oil and Natural Gas Sector Pneumatic Devices,” in 2014, requesting specific comment on available emissions data for pneumatic devices. One of the comments received regarding data presented in “Measurements of Methane Emissions at Natural Gas Production Sites in the United States”[96] was that the data set reported was dominated by extreme values. The commenter noted that the highest emitting controllers are simply controllers emitting at a large rate, regardless of their service or design type. These

[93] Ibid.
[94] Ibid.
[95] American Petroleum Institute (API). *Pneumatic Controllers*. Webinar Prepared and Presented to the U.S. Environmental Protection Agency. March 25, 2014.
[96] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

controllers can have high emissions because of factors, other than design, related to maintenance, malfunction, or defect.[97]

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Eliminating unnecessary valve positioners can save up to 18 scfh per device.[98]

6.3.2 Existing Federal, State and Local Regulations

6.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, new or modified continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants are subject to a VOC emission limit of zero (equivalent to non-natural gas-driven pneumatic controllers). Continuous bleed natural gas-driven pneumatic controllers in the production segment must have a bleed rate of 6 scfh or less.

6.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

For pneumatic controllers, Colorado and Wyoming have existing control requirements similar to those required under the 2012 NSPS and 2016 NSPS. Other states have permitting and

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[97] Allen, David. Comments Provided to the EPA on *Oil and Natural Gas Sector Pneumatic Devices-Peer Review Document*. University of Texas at Austin. June 2014.

[98] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

registration rules for controlling fugitive VOC emissions (which would include non-bleed emissions from pneumatic controllers).

Colorado requires that no- or low-bleed pneumatic controllers with a bleed rate of 6 scfh or less be installed for all new and existing applications (unless approved for use due to safety and/or process purposes) statewide (Regulation 7, XVIII.C.2). Where technically and economically feasible, Colorado requires no-bleed pneumatic controllers at facilities that are connected to the electric grid and using electricity to power equipment.

Wyoming requires the installation of low- or no-bleed pneumatic controllers with a bleed rate of 6 scfh or less at all new facilities. Upon modification of facilities, new pneumatic controllers must be low- or no-bleed and existing controllers must be replaced with no- or low-bleed controllers (at well site facilities only and not at natural gas processing plants).

Although some local rule requirements do not specifically require the control of VOC emissions from pneumatic controllers, local permit requirements (such as those required by the Bay Area Air Quality Management District) may require that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in a permit application. Under some situations where facilities use high-bleed devices, the permitting authority might require an owner or operator to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where high-bleed devices must be used, the permitting authority may require that the facility conduct fugitive monitoring and/or implement control requirements under conditions of their permit to operate.[99]

6.4 Recommended RACT Level of Control

Sections 6.4.1 and 6.4.2 present the recommended RACT level of control for continuous bleed natural gas-driven pneumatic controllers located at natural gas processing plants and continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

[99] Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities.* Bay Area Air Quality Management District. September 16, 2013.

6.4.1 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located at a Natural Gas Processing Plant

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the "Oil and Natural Gas Sector Pneumatic Devices" white paper, and existing regulations that control VOC emissions from pneumatic controllers, we recommend that VOC emissions from an individual continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant be controlled by RACT. As noted in section 6.3.2, both Colorado and Wyoming require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting at least 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers at natural gas processing plants have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). For existing individual continuous bleed pneumatic controllers at natural gas processing plants, our RACT recommendation is that controllers have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). Our rationale for selecting a natural gas bleed rate of 0 scfh (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 6.3.1.2 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. Therefore, the use of instrument air eliminates natural gas and VOC emissions from pneumatic controllers and supports a natural gas bleed rate of 0 scfh.

In order to meet an emission limit of 0 scfh, natural gas processing plants would likely need to use an instrument air system. The use of instrument air eliminates natural gas and VOC emissions from natural gas-driven pneumatic controllers. We believe that most natural gas processing plants already meet the recommended RACT level of control by driving controllers with instrument air or other non-gas-driven controls unless there is a specific need for a high-bleed pneumatic controller. Nonetheless, for those natural gas processing plants that do not have an installed instrument air system, the cost of control of installing three representative instrument air systems was evaluated under the 2012 NSPS and 2016 NSPS based on the emissions mitigated from the number of control loops the system can provide (see section 6.3.1.2 of this chapter). Based on this analysis, the cost of this option was considered to be reasonable for natural gas processing plants (see Table 6-7 of section 6.3.1.2 of this chapter). The cost of control per ton of VOC reduced was estimated at $1,700 - $2,800 without savings and $910 - $2,000 with savings. For determining potential cost impacts, a major assumption made was that processing plants are constructed at locations with sufficient electrical service to power the instrument air compression systems.

In summary, we recommend the following RACT for each continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant:

> RACT for Each Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant:[100] Each continuous bleed natural gas driven pneumatic controller located at a natural gas processing plant must have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).

6.4.2 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the “Oil and Natural Gas Sector Pneumatic Devices” white paper, and existing regulations that control VOC emissions from pneumatic controllers, we are recommending a natural gas bleed rate less than or equal to 6 scfh with limited exceptions described below as the RACT for controlling VOC emissions from continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline. We are also recommending that no requirements apply under RACT for pneumatic controllers that have a natural gas bleed rate less than or equal to 6 scfh that are located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

[100] In the NSPS, we excluded from the NSPS affected facility status non-natural gas-driven pneumatic controllers located at natural gas processing plants. Natural gas-driven controllers exempt from the zero VOC emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

As indicated in section 6.2.2 of this chapter, low-bleed pneumatic controllers can emit up to 6 scfh. Both Colorado and Wyoming conditionally require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting greater than 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers have a bleed rate of 6 scfh or less (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh). For purposes of this CTG, and consistent with the definition of high-bleed controller used for the 2012 NSPS, 2016 NSPS, and both the Wyoming and Colorado state regulations, a high-bleed pneumatic device is defined as emitting greater than 6 scfh to the atmosphere.

Although both Wyoming and Colorado specifically require low-bleed or no-bleed pneumatic controllers in place of high-bleed controllers (where technically and economically feasible), we are recommending a RACT emission limit of 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh) apply to each continuous bleed pneumatic controller. This approach allows flexibility in how a source chooses to limit VOC emissions from an applicable individual pneumatic controller and acknowledges that there may be circumstances where it is not practical to meet a 6 scfh limit. By requiring a limit be met, facilities have the option of controlling emissions by one or more options presented in section 6.3.1 of this chapter (e.g., replace a high-bleed device with a low-bleed device and implement enhanced monitoring to mitigate increased VOC emissions from poor maintenance/poor operation) depending on site-specific circumstances. We are including this flexibility in our recommended RACT to address the varied control options and applicability issues (e.g., instrument air systems require access to electrical power or a backup pneumatic controller and access to electric power or backup pneumatic controllers may not be available in remote locations) presented in section 6.3.1 of this chapter.

Although facilities would have flexibility in how they meet the recommended RACT level of control, by establishing an emission limit equal to the design bleed rate for a low-bleed device (6 scfh), we believe that most facilities would likely replace high-bleed controllers with low-bleed controllers (it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices).[101] For the production segment, we estimated that, on average, 1.41 tons of VOC would be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device.

As presented in section 6.3.1.1 of this chapter, the cost of replacing a high-bleed device with a new low-bleed device is on the order of $2,698 per device, and the cost of control in the production segment is estimated to be $210 per ton of VOC emissions reduced without savings. Considering the cost savings of gas recovered from installing a low-bleed device in place of a high-bleed device, it is estimated that there would be an overall net savings.

In summary, we recommend the following RACT for each single continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

> <u>RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline</u>: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller[102] must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).

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[101] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[102] In the NSPS, we excluded from NSPS pneumatic controller affected facility status continuous bleed natural gas-driven pneumatic controllers with a bleed rate not greater than 6 scfh (low-bleed controllers) located in the production segment. Continuous bleed natural gas-driven controllers exempt from the 6 scfh bleed rate emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

6.5 Factors to Consider in Developing Pneumatic Controller Compliance Procedures

6.5.1 Oil and Natural Gas Production (Individual Continuous Bleed Pneumatic Controller with a Natural Gas Bleed Rate Greater than 6 scfh Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline)

To ensure that each continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline is operated with a natural gas bleed rate less than or equal to 6 scfh (the recommended RACT level of control), we recommend that regulating agencies specify operating, recordkeeping and reporting requirements to document compliance. It is recommended that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to manufacturer's documentation.

It is recommended that air agencies require owners and operators of continuous bleed natural gas-driven pneumatic controllers that are subject to RACT maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) if applicable, provide a demonstration as to why the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required (the recommended RACT level of control); and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include (1) if applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 standard cubic feet per hour is required and the reasons why; and (2) the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

6.5.2 Natural Gas Processing Segment (Individual Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant)

To ensure each continuous bleed natural gas-driven pneumatic controller at natural gas processing plants is operated with a natural gas bleed rate of zero (the recommended RACT level of control), we suggest that air agencies specify operating, recordkeeping and reporting requirements to document compliance. We also suggest that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to the manufacturer's documentation. It is recommended that air agencies require owners and operators of pneumatic controllers maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) document that the natural gas bleed rate is zero; and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.0 PNEUMATIC PUMPS

The oil and natural gas industry uses a variety of pneumatic gas-driven pumps where there is no reliable electrical power to “control processing problems and protect equipment.”[103] Pneumatic pumps are “small positive displacement, reciprocating units used throughout the oil and natural gas industry to inject precise amounts of chemicals into process streams or for freeze protection glycol circulation.”[104] Most chemical injection pumps fall into two main types: (1) diaphragm pumps, generally used for heat tracing; or (2) plunger/piston, generally used for chemical and methanol injection. Pneumatic pumps driven by natural gas emit natural gas, which contains VOC. Other types of pneumatic pumps may be driven by gases other than natural gas and, therefore, do not emit VOC. The focus of this CTG is natural gas-driven pneumatic pumps. This chapter provides a description of pneumatic pumps that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also provides control techniques used to reduce VOC emissions from pneumatic pumps, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT for pneumatic pumps and the associated VOC emission reductions and costs.

7.1 Applicability

For the purposes of this CTG, a pneumatic pump is a positive displacement reciprocating unit used for injecting precise amounts of chemicals into a process stream or for glycol circulation. The pneumatic pump may use natural gas or another gas to drive the pump. The emissions and emission control options discussed herein would apply to natural gas-driven chemical/methanol and diaphragm pumps located at natural gas processing plants and well sites.

[103] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps*. EPA-600/R-96-080b. June 1996.
[104] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

7.2 Process Description and Emission Sources

7.2.1 Process Description

As noted above, pneumatic pumps are "positive displacement, reciprocating units used for injecting precise amounts of chemicals into a process stream or for glycol circulation."[105] Pneumatic pumps often make use of gas pressure where electricity is not readily available.[106] In the production segment, the supply gas is mostly produced natural gas, whereas in the processing segment, the supply gas may be compressed air. For natural gas-driven pneumatic pumps, characteristics that affect VOC emissions include the frequency of operation, the size of the unit, the supply gas pressure, and the inlet natural gas composition.[107]

Pneumatic pumps are generally used for one of three purposes: glycol circulation in dehydrators, hot oil circulation for heat tracing/freeze protection, or chemical injection. Glycol dehydrator pumps may recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.[108] Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels, and tanks. Chemical injection pumps (i.e., piston/plunger pumps or small diaphragm pumps) inject small amounts of chemicals, such as methanol, to prevent hydrate formation or corrosion inhibitors into process streams to regulate operations of a plant and protect the equipment.

Pneumatic pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of

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[105] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[106] Ibid.
[107] Ibid.
[108] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel.* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.[109]

Chemical injection pumps are positive displacement, reciprocating units designed to inject precise amounts of chemical into a process stream. Positive displacement pumps work by allowing a fluid to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged.[110]

Typical chemicals injected in an oil or natural gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H_2S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Because the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.[111]

Diaphragm pumps are positive displacement pumps, meaning they use contracting and expanding cavities to move fluids. Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid.[112]

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[109] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[110] Ibid.
[111] Ibid.
[112] GlobalSpec. *Diaphragm Pumps Information*. Available online - http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

Not all pneumatic pumps are natural gas driven. At sites without electrical service sufficient or reliable enough to power an instrument air compressor control system, mechanical or electrically powered pneumatic pumps may be used. Where reliable electrical service is available, sources of power other than pressurized natural gas, such as compressed instrument air may be used. Because these devices are not natural gas driven, they do not directly release natural gas or VOC emissions. Instrument air systems are feasible only at oil and natural gas industry locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power a compressor. This analysis assumes that natural gas processing plants are likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of natural gas-driven pumps.[113] The application of electrical controls is discussed further in section 7.3 of this chapter.

7.2.2 Emissions Data

7.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic pumps and the potential options available to reduce these emissions, numerous studies were consulted. Table 7-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."[114]

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[113] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

[114] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[g]
Greenhouse Gas Reporting Program[a]	EPA	2014	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks[b]	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry[c,d]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry[e]	EPA	1999	Nationwide	X	
Natural Gas STAR Program[f]	EPA	2012	Study Specific	X	X

[a] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.
[b] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report.* EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.
[d] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.
[e] U.S. Environmental Protection Agency. *Methane Emissions from the U.S. Petroleum Industry. Final Report*. Prepared for the U.S. Environmental Protection Agency by Radian International LLC. EPA-600/R-99-010. February 1999.
[f] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[g] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

7.2.2.2 Representative Pneumatic Pump Emissions

For this analysis, we consulted information in the appendices of Natural Gas STAR lessons learned documents on pneumatic pumps,[115,116] the GHGRP, the GHG Inventory, and

[115] U.S. Environmental Protection Agency. Lessons Learned: *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[116] U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. September 2004.

U.S. EPA/GRI Report.[117] The GHGRP and GHG Inventory use emission factors from the U.S. EPA/GRI Report. Similarly, we determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA/GRI Report.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in the production and processing segments and then estimate VOC and HAP emissions using the gas composition factors from the 2011 Gas Composition Memorandum. The specific gas composition ratio used for this analysis was 0.278 lbs VOC per pound methane in the production and processing segment. Table 7-2 summarizes the estimated average emission factors for a representative pneumatic pump for the production and processing segments for both methane and VOC.

Table 7-2. Average Emission Estimates per Pneumatic Device

Segment/Pump Type	Emission Factor Methane (scf/day) [a]	Emission Factor Methane (Mcf/yr)[b]	Emission Factor Methane (tpy)[c]	Emission Factor VOC (tpy)[d]
Production				
Diaphragm	446	163	3.46	0.96
Piston	48.9	18	0.38	0.11
Processing				
Small Diaphragm	446	163	3.46	0.96
Medium Diaphragm	446	163	3.46	0.96
Large Diaphragm	446	163	3.46	0.96
Small Piston	48.9	18	0.38	0.11
Medium Piston	48.9	18	0.38	0.11
Large Piston	48.9	18	0.38	0.11

[a] Data Source: EPA/GRI. *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*. June 1996 (EPA-600/R -96-080m), Sections 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps.
[b] Assumes 365 days/yr operation in natural gas production and processing.
[c] Assumes density of methane is 19.26 g/scf.
[d] Assumes 0.278 VOC content per pound of methane.

[117] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps.* June 1996 (EPA-600/R -96-080m).

7.3 Available Controls and Regulatory Approaches

7.3.1 Available VOC Emission Control Options

Natural gas-driven pneumatic pumps emit VOC emissions as part of their normal operation. Depending on the type of pump and the constraints of the location, companies can utilize a variety of technologies that have been developed over the years. In situations where the replacement of natural gas-driven pumps with electric, solar and instrument air pumps is not feasible, emissions can be captured and routed to a VRU or to a combustion device.

Sections 7.3.1.1 and 7.3.1.2 discuss the control of VOC emissions by replacing natural gas-driven pumps with solar pumps and electric pumps. Section 7.3.1.3 discusses the use of an instrument air system to drive the pneumatic pump in order to eliminate VOC emissions. Lastly, section 7.3.1.4 discusses reducing VOC emissions by routing emissions from the pump to a combustion device, and section 7.3.1.5 discusses capturing VOC emissions using a VRU.

7.3.1.1 Solar Pumps

Description

Solar pumps provide the same functionality as natural gas-driven pumps and can be utilized at remote sites where electricity is not available. However, peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices" noted that they predominantly operated solar-powered pneumatic pumps for chemical injection and the pumps failed as early as after two to three cloudy days due to insufficient battery charge.[118] When solar pumps are properly charged, a solar-charged DC pump can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 psig and have no VOC emissions. Converting natural gas-driven chemical pumps can reduce methane emissions by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump for all segments of the oil and natural gas industry.[119] Based on the gas composition for natural gas in the production segment, we estimate that replacement of a pneumatic pump with a solar-powered pump will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy for a piston pump.

[118] Reese, Carrie, Environmental Compliance Manager. Comments on the Oil and Natural Gas Sector Pneumatic Devices. Pioneer Natural Resources.
[119] U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

Control Effectiveness

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Although, as stated above, solar-powered pumps are capable of pumping up to 100 gallons per day, they are typically used for low volume applications to inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to the low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

Cost Impacts

The primary costs associated with conversion to solar pumps are the initial capital expenditures. Solar pumps generally have low maintenance costs, which are typically lower than natural gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar-powered pumps includes the capital cost of the pump and its associated operating costs. The operating costs are estimated to be 10 percent of the capital cost. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"[120] the capital (purchase) cost for a solar-powered electric pump is approximately $2,000 with solar panels having a lifespan of 15 years and electric motors lasting 5 years. The total capital cost, including installation and labor is $2,227 (2012 dollars). We estimate there would be no additional annual operating costs for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a pneumatic pump with a solar pump is $317. In addition, the use of solar pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on $4.00 per Mcf would be $786 per year per diaphragm pump and $87 per year per piston pump.

[120] U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

7.3.1.2 Electric Pumps

Description

Electric pumps provide the same functionality as natural gas-driven pumps, and are only restricted by the use of reliable power. Electric pumps have no VOC emissions, and converting a natural gas-driven pneumatic pump to an electric pump can reduce VOC emissions by an estimated 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Control Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in VOC emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at natural gas processing plants or large dehydration facilities that have access to reliable electric power.

Cost Impacts

The primary costs associated with converting natural gas-driven pumps to electric pumps are the initial capital expenditures, installation and ongoing operation and maintenance. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"[121] the cost of an electric pump to replace a diaphragm pump is $4,647 and to replace a piston pump is $1,819 in 2012 dollars depending on the horsepower of the unit.[122] The annual operating costs for an electric pump are estimated to be $293. Based on these costs annualized over the life expectancy of the pump at a 7 percent discount rate, the annualized cost for an electric pump to replace a diaphragm pump is $954, and $552 to replace a piston pump. In addition, the use of electric pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on $4.00 per Mcf would be $786 per year per diaphragm pump and $87 per year per piston pump.

[121] Ibid.

[122] U.S. Environmental Protection Agency. *Lessons Learned*. *Replacing Gas-Assisted Glycol Pumps with Electric Pumps*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006. October 2006.

7.3.1.3 Instrument Air System

Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same pneumatic pumps can be used for natural gas and compressed air, without altering any of the parts of the pneumatic pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to an adequate and reliable source of electricity can install an instrument air system. The following, taken from the Natural Gas STAR document, "PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air,"[123] describes the major components of an instrument air system:

(1) Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical emission rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.

(2) A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, natural gas-driven pneumatic systems can run uninterrupted on a 24-hour, 7- day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be feasible for remote locations, which would both reduce VOC emissions and energy consumption. Small natural gas-powered fuel cells are also being developed.

[123] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

(3) Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

(4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Control Effectiveness

Instrument air eliminates all emissions from natural gas-driven pneumatic pumps, but can only be utilized in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more economical and, therefore, more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning.[124] Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump. Based on the gas composition for natural gas in the production segment, we estimate that converting a natural gas-driven pneumatic pump to instrument air will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Cost Impacts

As stated previously, instrument air conversions require a compressor with a capacity based on the number of control loops at the location. The compressor size is equivalent to the volume of gas used by the control loops after adjusting for gas losses during drying, plus any utility air necessary at the facility. This volume can either be calculated via a meter or utilizing a rule of thumb of one cubic foot per minute (cfm) of instrument air per control loop.[125]

The costs associated with instrument air systems are primarily capital costs for the compressor(s), air dryer and the volume tank, but also include operational costs for electricity to

[124] Ibid.
[125] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

drive the compressor motor. Other components of the instrument air system, including piping, control instruments and valve actuators, would already be in place for a gas system. We assume that existing processing plants have an instrument air system in place, including backup systems, and that the cost of increasing air load on the system would be confined to the incremental cost associated with upgrading or replacing the compressor and connecting the pumps to the system. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps. Table 7-3 summarizes cost estimates to replace various size compressors in an existing instrument air system.

Table 7-3. Cost of Compressor Replacement for Existing Instrument Air System ($2012)

Compressor Size	Total Capital Cost[a]	Annualized Cost[b]	Total O&M Cost[c]	Annual Cost[d]
Small	$5,999	$854	$9,197	$10,051
Medium	$29,989	$4,270	$28,002	$32,271
Large	$52,779	$7,515	$64,880	$72,394

[a] 2016 NSPS TSD.
[b] Annualized capital cost using a 7 percent interest rate and an equipment life of 10 years.
[c] The total O&M includes both the annual labor cost and the annual power cost.
[d] The total annual cost includes the annualized capital cost and the total O&M cost.

7.3.1.4 Route Emissions to an Existing or New Combustion Device

Description

Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. It is assumed that most processing plants and large dehydration facilities have at least one existing combustion device onsite.

Control Effectiveness

Routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas discharged from the pump, but rather combusts the gas. Based on the gas composition for natural gas in the production segment, we estimated that routing emissions to a combustion device would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital and operating costs. Based on costs for a combustion device provided in the 2015 NSPS TSD, the capital cost for installing a new combustion device to control emissions is estimated to cost $34,250 and the annual operating cost is $17,001 in 2012 dollars. Based on the life expectancy for a combustion device, we estimate the annualized cost of installing a new combustion device to be approximately $21,877, using a 7 percent discount rate. The capital cost for routing emissions to an existing control device to control emissions is estimated to be $5,433 with an annualized cost of $774, using a 7 percent discount rate. Because the natural gas captured is combusted there is no gas savings associated with the use of a combustion device to reduce VOC emissions. Table 7-4 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing combustion device.
Table 7-5 presents the cost of control for routing natural gas-driven pump emissions to a new combustion device.

Table 7-4. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)
Diaphragm Pumps			
Production	0.91	$774	$847
Processing	0.91	$774	$847
Piston Pumps			
Production	0.10	$774	$7,709
Processing	0.10	$774	$7,709

Table 7-5. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)
Diaphragm Pumps			
Production	0.91	$21,877	$23,944
Processing	0.91	$21,877	$23,944
Piston Pumps			
Production	0.10	$21,877	$218,017
Processing	0.10	$21,877	$218,017

7.3.1.5 Route Emissions to a Vapor Recovery Unit (VRU)

Description

Vapor recovery units capture low-pressure vapor streams, increase the pressure by means of a compressor, and then route the vapor stream to a process or other useful purpose. These systems typically include a backup compressor system to allow for shutdowns and repairs. Vapor recovery units are more economical for facilities with multiple natural gas emission sources that can be routed to the VRU. Some of these other emission sources can include tanks, dehydrators, and compressors and as a result, VRUs are more common at natural gas processing plants. Vapor recovery units are discussed in greater detail in section 4.3.1.1 of chapter 4 of this document.

Control Effectiveness

Use of a vapor recovery technology has the potential to reduce the VOC emissions from natural gas-driven pumps by 100 percent if all vapor is recovered. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, we estimate that routing emissions from a natural gas-driven pump to an existing or newly installed VRU can reduce the VOC emitted by approximately 95 percent (accounting for any reduced efficiency that may occur) while, at the same time, capturing the natural gas for beneficial use. We estimate that methane emission reductions for routing gas to a VRU to be 3.29 tpy for a diaphragm pump and 0.36 tpy for a piston pump. Based on the gas composition for natural gas in the production segment, we estimate that routing emissions to a VRU can reduce VOC emissions by 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Based on costs for a VRU provided in the 2015 NSPS TSD, we estimate the capital cost of installing a VRU to be $104,111 and the annual operation and maintenance cost to be $9,932 in 2012 dollars. The total annualized cost of a new VRU is estimated to be $24,755 based on a 7 percent discount rate.

If a VRU is already onsite, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. We estimated the cost of routing emissions to an existing VRU to be $5,433 in 2012 dollars. The annualized cost of routing natural gas emissions to an existing VRU is estimated to be $774 based on a 7 percent discount rate. In addition, there is potential for beneficial use of natural gas recovered through the VRU. We estimated the annual natural gas recovered to be 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The resulting natural gas savings is estimated to be $749 per diaphragm pump and $84 per piston pump, per year based on a value of $4.00 per Mcf of natural gas recovered. Table 7-6 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing VRU. Table 7-7 presents the estimated VOC cost of control for routing gas-driven pump emissions to a new VRU.

Table 7-6. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	$774	$847	$27
Processing	0.91	$774	$847	$27
Piston Pumps				
Production	0.10	$774	$7,709	$6,876
Processing	0.10	$774	$7,709	$6,876

Table 7-7. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	$24,755	$27,094	$26,275
Processing	0.91	$24,755	$27,094	$26,275
Piston Pumps				
Production	0.10	$24,755	$246,697	$245,864
Processing	0.10	$24,755	$246,697	$245,864

7.3.2 Existing Federal, State and Local Regulations

7.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

The EPA has finalized federal requirements for natural gas-driven pneumatic pumps under subpart OOOOa. Under subpart OOOOa, each natural gas-driven diaphragm pump located at a natural gas processing plant must have zero natural gas emissions, and each natural gas-driven diaphragm pump located at a well site must capture and route emissions to a control device or process if there is an existing control device or process available onsite. Subpart OOOOa requires that VOC and methane emissions be reduced by 95 percent or greater unless the existing control device or process is not capable of reducing emissions by 95 percent or greater, unless (1) there is no control device onsite, (2) it is technically infeasible, or (3) the control device cannot achieve 95 percent control. Subpart OOOOa also includes an exemption from control requirements where a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year.

7.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source may be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

At least one state (Wyoming) requires emissions associated with the discharge streams from all natural gas-operated pneumatic pumps be controlled by at least 98 percent or routed into a closed-loop system (e.g., sales line, collection line, fuel supply line). Several states also have registration rules for controlling fugitive VOC emissions (which may include fugitive emissions from pneumatic pumps).

7.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices." Based on our evaluation of these data and information, we recommend that VOC emissions from pneumatic pumps be controlled.

Our recommended RACT for an existing individual natural gas-driven diaphragm pump located at the well site is to capture and route VOC emissions to a control device or process where there is an existing control device or process available onsite. Our rationale for this recommendation is that, although the production segment includes both well sites and gathering and boosting stations, we currently only have reliable information for pumps located at well sites. We have determined that the cost of control for routing VOC emissions to an existing onsite control device or process would be reasonable. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be $847 per ton of VOC reduced for diaphragm pumps, without gas savings, and $27 per ton of VOC reduced for diaphragm pumps if a VRU is used and gas savings are considered. We do not consider requiring control where there is not an existing control device or process onsite to be reasonably available technology, and the cost per ton of VOC reduced was estimated at greater than $20,000 for diaphragm pumps. While we are not recommending that the owner or operator be required to install a control device to control pneumatic pump emissions if one is not already available, we note that control devices will likely be installed onsite for other purposes under RACT or other regulations and will be available to control emissions from pneumatic pumps to a 95 percent control level.

For purposes of our recommended RACT, a natural gas-driven diaphragm pump is a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of our recommended RACT. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

We do not recommend RACT apply to an existing individual natural gas-driven piston pump because currently available information (including information received on the draft CTG and 2015 NSPS proposal) indicates that piston pumps are low emitting because of their small size, design and usage patterns. We determined piston pumps have emission rates between 2.2 to 2.5 scf/hr based on a joint report from the EPA and the Gas Research Institute on methane emissions from the natural gas industry. This approach is consistent with the manner in which we addressed low-bleed pneumatic controllers. After considering the low emission rates of low-bleed pneumatic controllers, we do not recommend RACT apply to these sources. Similarly, based upon the information that we have on the low emission rates of piston pumps, we are not recommending RACT apply to these sources because VOC emissions are low and would not be reasonable to control in the same manner that we recommend for diaphragm pumps. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be $7,709 per ton of VOC reduced for piston pumps, without gas savings, and $6,876 per ton of VOC reduced for piston pumps if a VRU is used and gas savings are considered. Requiring control where there is not an existing control device or process onsite was estimated to cost more than $200,000 per ton of VOC reduced for piston pumps.

For existing natural gas-driven diaphragm pumps at well sites, we recommend that air agencies require VOC emissions be controlled by 95 percent. Our rationale for recommending this level of emission reduction is supported by the control level achievable on a continuing basis by control devices and processes already located onsite or later installed onsite to control other emissions under RACT or other regulations. We expect that newly-installed control devices will achieve emission reductions because owners or operators are installing them to meet control requirements for other sources. In the unlikely circumstance where a control device that can achieve a 95 percent reduction is not available onsite, we recommend that owners and operators still be required to control VOC emissions to the level achievable by the control device. We recommend that owners and operators in those instances be required to maintain documentation of the percent control the onsite control device is designed to achieve. We make this additional recommendation because it will achieve emission reductions with regard to pneumatic pumps even in the unlikely circumstance that the only available control device cannot achieve a 95 percent reduction.

We also recommend that air agencies allow for an exemption based on technical infeasibility. We recommend a technical infeasibility exemption be allowed based on information we received from industry that indicates that there may be circumstances where there is insufficient gas pressure or control device capacity, making it technically infeasible to capture and route pneumatic pump emissions to a control device or process.

We recommend that, at well sites, if a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year, the pump not be subject to the recommended control requirements. We make this recommendation to account for those intermittently used pumps/portable pumps where VOC emissions would be lower than assumed in our analysis (i.e., our analysis assumes that diaphragm pumps are operated 40 percent of the time evenly throughout the year) and not reasonable to control.

Our recommended RACT for existing diaphragm pumps located at natural gas processing plants is that they have zero VOC emissions (or 100 percent control) (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring an emission rate greater than zero). Our rationale for selecting a VOC emission rate of zero (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 7.3.1.3 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic system. Therefore, the use of instrument air eliminates VOC emissions from each gas-driven diaphragm pump and supports a VOC emission rate of zero.

In summary, we recommend the following RACT for pneumatic pumps in the oil and natural gas industry:

(1) Each Diaphragm Pump Located at a Natural Gas Processing Plant: Require zero VOC emissions (or 100 percent control). This can be achieved by use of an instrument air system in place of natural gas-driven pump.

(2) Each Diaphragm Pump Located at a Well Site: Require that VOC emissions be captured and routed to an existing control device or process that is located onsite, unless it is technically infeasible to route emissions to the existing control device or process. Require 95 percent control of VOC emissions, unless the existing control device or process cannot achieve 95 percent control. If the existing control device cannot achieve a 95 percent control, still require the emissions to be routed to the existing onsite control device to control emissions to the extent achievable and maintain documentation of the percent control the onsite control device is designed to achieve. If there is no existing control device at the location of the pump, submit a certification that there is no device. If a control device is subsequently added to the site where the pump is located, then the VOC emissions from the pump must be captured and routed to the newly installed control device.

Although sources have a choice on how they meet the RACT level of control, the technologies that will likely be used to meet the RACT level of control for each natural gas-driven diaphragm pump at a well site are either capturing and routing the VOC emissions to an onsite existing combustion device (or a subsequently installed combustion device) or capturing and routing the VOC emissions to a process using an onsite existing VRU (or a subsequently installed VRU).

Similarly, the technology that will likely be used to meet the RACT level of control for each diaphragm pump located at a natural gas processing plant is the use of an existing instrument air system assumed to already exist onsite at natural gas processing plants.

7.5 Factors to Consider in Developing Pneumatic Pump Compliance Procedures

7.5.1 Oil and Natural Gas Production Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at well sites that meet RACT by capturing emissions and routing to a control device be connected through a closed vent system and that the closed vent system be designed with no detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of part 60, and ongoing monthly, olfactory and auditory inspections). We recommend that you require that owners and operators conduct an assessment and certify that the closed vent system is of sufficient design and capacity to ensure that emissions are routed to the control device. We recommend air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm or initiates notification via remote alarm to the nearest field office when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

Secondly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites provide certifications for when (1) there is no existing control device or process onsite, or (2) capturing and routing to an existing control device or process is not technically feasible.

Lastly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites maintain records documenting where (1) intermittently-used/portable diaphragm pumps operate for any period of time each calendar day for less than a total of 90 calendar days per year, (2) an onsite control device or process is designed to achieve less than 95 percent reduction, and (3) a diaphragm pump is routed to a control device or a process and the control device or process is subsequently removed.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.5.2 Natural Gas Processing Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at natural gas processing plants maintain records documenting (1) the location and manufacturer's specifications of each pneumatic pump, (2) that the natural gas bleed rate is zero, and (3) deviations in cases where a pneumatic pump was not operated in compliance with RACT. We also recommend that air agencies require owners and operators submit annual reports that include records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

8.0 EQUIPMENT LEAKS FROM NATURAL GAS PROCESSING PLANTS

This chapter presents the causes for equipment leaks from natural gas processing plants, and provides emission estimates for “model” facilities in the processing segment of the oil and natural gas industry. Methods that are designed to reduce equipment leak emissions are presented, along with our recommended RACT, and the associated VOC emission reductions and cost impacts for equipment leaks from natural gas processing plants.

This CTG and the recommended RACT included in this CTG replaces the following: *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

8.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to the group of all equipment (except compressors and sampling connection systems) within a process unit located at a natural gas processing plant in VOC service or in wet gas service, and any device or system that is used to control VOC emissions (e.g., a closed vent system). For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, the piece of equipment must contain or contact the field gas before the extraction step at a natural gas processing plant. Equipment is defined as each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service.

8.2 Process Description and Emission Sources

8.2.1 Process Description

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the natural gas from the processing facility to the transmission stations.

There are several potential sources of equipment leak emissions at natural gas processing plants. Equipment such as pumps, pressure relief devices, valves, flanges, and other connectors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and valves may leak for reasons other than faulty seals, such as an improperly installed cap on an open-ended line. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following subsections describe potential equipment leak sources and the magnitude of the VOC emissions from natural gas processing plants.

Due to the large number of valves, pumps, and other equipment within natural gas processing plants, VOC emissions from leaking equipment can be significant (chapter 2.2 of the 1983 CTG[126] presents a description of these equipment components and is not repeated here).

8.2.2 Equipment Leak Emission Data and Emission Factors

8.2.2.1 Summary of Major Studies and Emission Factors

The 2012 NSPS TSD evaluated emissions data from equipment leaks collected from chemical manufacturing and petroleum production to assist in the development of control strategies for reducing VOC emissions from these sources.[127,128,129] Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Leaks."[130]

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[126] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

[127] Memorandum from David Randall, RTI and Karen Schaffner, RTI to Randy McDonald, U.S. Environmental Protection Agency. *Control Options and Impacts for Equipment Leaks: Chemical Manufacturing Area Source Standards*. September 2, 2008.

[128] Memorandum from Kristen Parrish, RTI and David Randall, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC on SOCMI*. October 30, 2007.

[129] Memorandum from Kristen Parrish, RTI, David Randall, RTI, and Jeff Coburn, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC in Petroleum Refineries*. October 30, 2007.

[130] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks. Report for Oil and Natural Gas Sector Leaks Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014.

Table 8-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[r]
Protocol for Equipment Leak Emission Estimates[a]	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks[b]	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program[c]	EPA	2014	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks[d]	EPA	Annual	Nationwide	X	
Methane Emissions from the Natural Gas Industry[e,f,g,h]	EPA/GRI	1996	Nationwide	X	X
Methane Emissions from the U.S. Petroleum Industry[i]	EPA	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry[j]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[k]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories[l]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[m]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements[n]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities[o]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[p]	U.S. Energy Information Administration	2007-2009	Nationwide		

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[r]
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations[q]	EPA	1999		X	X

[a] U.S. Environmental Protection Agency, *Protocol for Equipment Leak Emission Estimates.* Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.
[b] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* June 1996 (EPA-600/R-96-080h).
[c] U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.
[d] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[e] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996.
[f] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.
[g] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996.
[h] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 6: Vented and Combustion Source Summary Emissions*. EPA-600/R-96-080f. June 1996.
[i] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry, Draft Report*. June 14, 1996.
[j] ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.
[k] ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States*. Prepared for Western Governors' Association. December 27, 2005.
[l] ENVIRON International Corporation. *Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories Prepared for Central States Regional Air Partnership*. November 2008.
[m] Independent Petroleum Association of America. *Oil and Gas Producing Industry in Your State*.
[n] Armendariz, Al. *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*. Prepared for Environmental Defense Fund. January 2009.
[o] Eastern Research Group, Inc. *Emissions from Oil and Gas Production Facilities*. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.
[p] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.
[q] Eastern Research Group, Inc. *Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operation*. Prepared for the U.S. Environmental Protection Agency. September 1999.
[r] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

8.2.2.2 Natural Gas Processing Model Plant

Natural gas processing plants can consist of a variety of combinations of process equipment and components. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, the 2011 NSPS TSD and the 2012 NSPS TSD used a model plant approach.

Information related to equipment counts were obtained from a natural gas industry report.[131] This document provided average equipment counts for gas production and gas processing segments. These average counts were used to develop a model plant. These equipment counts are consistent with those contained in the EPA's analysis to estimate methane emissions conducted in support of the GHGRP. The natural gas processing model plant is discussed in the following section. A summary of the model plant production equipment counts for a gas processing facility is provided in Table 8-2.

Table 8-2. Equipment Counts for Natural Gas Processing Model Plant

Equipment	Equipment Count (non-compressor equipment)
Valves	1,392
Connectors	4,392
Open-Ended Lines (OEL)	134
Pressure Relief Valve (PRV)	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

8.2.2.3 Natural Gas Processing Model Plant Emissions

<u>Overview of Approach</u>

The EPA gathered equipment leak data and cost information for the development of the proposed National Uniform Emission Standards for Equipment Leaks rule (58 FR 17898, March 26, 2012). These Uniform Standards data were used to estimate baseline emissions for a natural

[131] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Table 4-13, June 1996. (EPA-600/R-96-080h).

gas processing model plant for the 2012 NSPS STSD and provide the baseline and controlled emission options for processing plants presented in this CTG.[132,133]

The baseline emissions were defined as being equivalent to a 40 CFR part 60, subpart VV (subpart VV) leak detection and repair (LDAR) program, which represents the same set of requirements that apply to natural gas processing plants under 40 CFR part 60, subpart KKK (subpart KKK). The 2012 NSPS requires the implementation of 40 CFR part 60, subpart VVa (subpart VVa) and currently applies to natural gas processing plants constructed or modified after August 23, 2011. It is assumed that natural gas processing plants constructed, reconstructed or modified on or before August 23, 2011 currently still comply with subpart KKK, which is similar to the control level of subpart VV. We evaluated requiring a similar subpart VVa level of control to these plants as was required under the 2012 NSPS. We used leak frequency data (refers to the estimated percentage of equipment that will be found leaking at a given leak definition) to calculate emission estimates, in addition to several other sources of information (including the Protocol for Equipment Leak Emissions Estimates and industry data).[134] Table 8-3 provides a summary of the equipment leak frequency data used for the natural gas processing model plant. Emission factors are the estimated leak rates for an equipment type at a given leak definition and are normally given in kg/hr/piece of equipment. Table 8-4 provides a summary of the VOC equipment leak emission factors representing the subpart VVa level of control that was used for the natural gas processing model plant.

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[132] Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS. *Analysis of Emission Reduction Techniques for Equipment Leaks*. December 21, 2011.
[133] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.
[134] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. November 1995. EPA-453/R-95-017.

Table 8-3. Summary of Equipment Leak Frequency for Natural Gas

LDAR Program[a]	Valves	Connectors
Baseline	1.18/1.18	NA
Valves	5.95/1.91	NA
Connectors	NA	1.70/0.81

NA = Not Applicable; no equipment leak frequency percent data were available.
Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 5.
[a] The leak frequencies provided in the tables are presented as initial leak frequency and subsequent leak frequency under the subpart VVa level of control.

Table 8-4. Summary of VOC Equipment Leak Emission Factors for the Natural Gas Processing Model Plant

Component	Uncontrolled (kg/comp-hr)	Baseline (kg/comp-hr)[a]	Subpart VVa Control Level (kg/comp-hr)[b]
Valves	3.71E-04	2.24E-04	8.85E-05
Connectors	1.04E-04	1.04E-04	3.95E-05
OEL	2.30E-03	7.34E-05	NA
PRV	1.60E-01	9.80E-02	NA

NA = Not Applicable
Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 7.
[a] The baseline option is assumed to be equivalent to a subpart VV LDAR program.
[b] Assumed to be equivalent to a subpart VVa LDAR program.

8.3 Available Controls and Regulatory Approaches

8.3.1 Available VOC Emission Control Options

The EPA has determined that leaking equipment, such as valves, pumps, and connectors are a significant source of VOC emissions from natural gas processing plants. The following subsections describe the techniques used to reduce emissions from these sources.

8.3.1.1 Leak Detection and Repair Program

The most commonly employed control technique for equipment leaks is the implementation of an LDAR program. Emission reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, and reduce emissions fees. An effective LDAR program will target leaking equipment by establishing leak definitions and require work practices to mitigate the leaks, such as monitoring frequencies for specific types of equipment (i.e., valves, pumps, and connectors). Other elements of an effective LDAR program include:

(1) Identifying Equipment,
(2) Monitoring Equipment,
(3) Repairing Equipment,
(4) Recordkeeping, and
(5) Reporting.

The primary sources of equipment leak emissions from natural gas processing plants are valves and connectors because these are the most prevalent equipment and can number in the thousands (see Table 8-2). The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, equipment type, and service (e.g., light liquid, heavy liquid, gas/vapor). Most NSPS regulations that were promulgated prior to 2007 have a valve leak definition of 10,000 ppm, while many National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations use a 500 ppm leak definition for valves or 1,000-ppm leak definition for other equipment such as pumps. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around equipment), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking equipment is EPA Reference Method 21 (40 CFR part 60, appendix A-7). Method 21 is a procedure used to detect VOC leaks from equipment using a toxic vapor analyzer (TVA) or organic vapor analyzer (OVA).

A second method for monitoring to detect leaking components is optical gas imaging (OGI) using an infrared (IR) camera. The IR camera may be passive or active. The operator uses the passive IR cameras to scan an area to produce images of equipment leaks from a number of sources. Active IR cameras point or aim an IR beam at a potential source to indicate the presence of gaseous emissions (equipment leaks). An equipment leak is any emissions that are visualized by an OGI instrument. The optical imaging camera can be very efficient in monitoring multiple pieces of equipment in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of the equipment leak.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are monitored separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

In addition, other monitoring tools, such as soap solution and electronic screening devices, can be used to find equipment leaks from certain types of equipment. Other factors that can improve the efficiency of an LDAR program include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

Subpart VVa LDAR Program

One LDAR option to control VOC emissions from natural gas processing plant equipment leaks is the implementation of the subpart VVa LDAR program. This program is similar to the subpart VV monitoring program (requirements are cross-referenced in subpart KKK), but finds more leaks due to the lower leak definition, increased monitoring frequency, and the addition of connectors to the components being monitored, thereby achieving better emission reductions.

Description

The subpart VVa LDAR program requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measures the concentration of the organics if the component is leaking. Connectors and valves have a leak definition of 500 ppm. Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves must be monitored within five days after a pressure release event to ensure they are operating without any detectable emissions (e.g. at a concentration less than 500 ppm above background). Compressors are not included in this leak detection and repair option and are regulated separately.

<u>Control Effectiveness</u>

The control effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. The control effectiveness of a leak program can vary from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition.[135] Descriptions of the frequency of monitoring and leak definition are described further below.

Monitoring Frequency. The monitoring frequency is the number of times each piece of equipment is checked for leaks over a given period of time. With more frequent monitoring, leaks are found and repaired sooner, thus providing higher control effectiveness.

Leak Definition. The leak definition describes the local VOC concentration at the surface of an equipment source where indications of VOC emissions are present. The leak definition is an instrument meter reading, in parts per million based on a reference compound. Decreasing the leak definition generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The 2012 NSPS STSD calculated incremental emission reductions from the baseline requirements (assuming that an LDAR program equivalent to the subpart VV/subpart KKK LDAR program is currently implemented at natural gas processing plants), and the leak frequency and emission factors from a supporting document for the Equipment Leak Uniform Standards were used to calculate the emission reductions and costs. The natural gas processing plant component counts (see Table 8-2) were obtained from an EPA/GRI document.[136] The incremental VOC emission reductions for implementing a subpart VVa leak detection and repair program (as determined in the 2012 NSPS STSD) for the natural gas processing model plant was calculated to be 13 percent.

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[135] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[136] GRI/EPA Research and Development. *Methane Emissions from the Natural Gas Industry; Volume 8: Equipment Leaks*. June 1996. EPA-600/R-96-080h.

Cost Impacts

Table 8-5 presents a summary of the incremental capital and annual costs and the cost of control (estimated in the 2012 NSPS STSD) from baseline (subpart VV) to implementing subpart VVa for the gas processing model plant. The costs obtained from the 2012 NSPS TSD have been converted to 2012 dollars from 2008 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[137]

Table 8-5. Summary of the Gas Processing Model Plant VOC Cost of Control for the Subpart VVa Option

Annual VOC Emission Reductions (tpy)	Capital Cost ($2012)	Annual Cost ($2012/year)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings[a]
4.56	$8,499	$12,959	$2,844	$2,010

[a] With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of $4/Mscf. The VOC/methane ratio was assumed to be 0.278.

Table 8-6 provides a summary of the capital and annual costs and the cost of control on a component basis for the natural gas processing model plant.

Table 8-6. Summary of the Gas Processing Component VOC Cost of Control for the Subpart VVa Option

Component	Annual VOC Emission Reductions (tpy)	Capital Cost ($2012)	Annual Cost ($2012/year)	VOC Cost of Control ($2012/ton)	
				Without Savings	With Savings[a]
Valves	1.82	$5,231	$9,280	$5,095	$4,261
Connectors	2.74	$8,374	$4,405	$1,610	$776

[a] With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of $4/Mscf. The VOC/methane ratio was assumed to be 0.278.

8.3.1.2 Leak Detection and Repair Program with Optical Gas Imaging

Another option to control VOC emissions is the implementation of a program that uses OGI to detect equipment leaks. The alternative work practice for equipment leaks in §60.18(g) of

[137] U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator (GDPDEF), retrieved from FRED, Federal Reserve Bank of St. Louis https://research.stlouisfed.org/fred2/series/GDPDEF. March, 26, 2015.

40 CFR part 60, subpart A allows the use of an OGI instrument to monitor equipment for leaks. This option is currently available for monitoring equipment leaks from valves, pumps, connectors and other equipment that is subject to monitoring in subpart VVa.

The alternative work practice requires periodic monitoring, based on the detection sensitivity level (grams per hour), of the affected equipment using OGI and an annual monitoring survey of the affected equipment using a Method 21. Method 21 monitoring allows the facility to determine the concentration of a leak and to then use emission factors found in the EPA's emissions leak protocol to quantify emissions from equipment leaks, because the OGI system can only provide the presence of the equipment leaks.

Modeling results, conducted in support of the alternative work practice standard, showed a work practice repeated bimonthly with a detection limit of 60 g/hr range was equivalent to existing Method 21 work practices. The model generated different detection limits for the 500 and 10,000 ppm thresholds in existing rules. Based on modeling, the alternative work practice standard reflects the mass detection limit for 500 ppm, thus, providing equivalency for both 500 and 10,000 ppm thresholds.[138] The alternative work practice option is assumed to have the same control effectiveness as the subpart VVa monitoring program.

8.3.2 Existing Federal, State and Local Regulations

8.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Federal regulations that regulate VOC emissions from equipment leaks at natural gas processing plants include 40 CFR part 60 subpart OOOOa, subpart OOOO, and subpart KKK; and the 1983 CTG document (established a recommended RACT for VOC for natural gas processing plants at a level of control equivalent to subpart KKK).

8.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed,

[138] 73 FR 78199, December 22, 2008.

what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

We assume that all states currently regulate equipment leaks at existing natural gas processing plants at the 1983 CTG document and subpart VV level of control.

8.4 Recommended RACT Level of Control for Equipment Leaks from Equipment at Natural Gas Processing Plants

As discussed in section 8.3.2 of this chapter, existing federal, state and local regulations already require the reduction of VOC emissions using an LDAR program. The 2012 NSPS requires a 40 CFR part 60 subpart VVa LDAR monitoring program for processing plants. The 2012 NSPS reported a cost of control for natural gas processing plants to be $2,844 per ton of VOC removed for the 40 CFR part 60 subpart VVa option.

Based on costs and existing LDAR programs that are already employed at natural gas processing plants, we recommend that RACT for natural gas processing plants be the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service. This RACT recommendation would increase the stringency from the currently implemented LDAR programs at most existing natural gas processing plants (that were built prior to 2012) in VOC service by lowering the leak definitions, increasing the monitoring frequency, and including additional equipment. The subpart VVa leak detection and repair program requires the annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (less than 500 ppm above background). The estimated annual incremental VOC emission reductions for the recommended RACT for a natural gas processing plant was estimated to be 4.56 tpy (see Table 8-5 of this chapter). The annual VOC emission reductions assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. Table 8-5 presents the gas processing model plant VOC cost of control for the recommended RACT. The costs assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. The recommended RACT VOC cost of control is estimated to be $2,844 per ton of VOC reduced without savings and $2,010 with savings.

In summary, we recommend the following RACT for equipment leaks at natural gas processing plants:

> RACT for Equipment Leaks at Natural Gas Processing Plants: We recommend the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service.

8.5 Factors to Consider in Developing Equipment Leak Compliance Procedures

Existing natural gas processing plants that would be subject to the recommended RACT are already subject to an LDAR program and the basic elements of the LDAR program for the facility are in place. However, the LDAR program would need to be modified to increase the stringency from the currently implemented LDAR program by requiring annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), and lowering the leak definition for valves (500 ppm). As with the currently implemented LDAR program, to ensure that equipment in VOC service that leak at natural gas processing plants are properly monitored and repaired under the LDAR RACT recommendations, we suggest that air agencies specify monitoring frequency, equipment repair, and recordkeeping and reporting requirements to document compliance.

Monitoring frequencies vary according to the applicable regulation, but are typically weekly, monthly, quarterly and yearly. The monitoring frequency depends on the equipment type and periodic leak rate for the equipment. For each piece of equipment that is found to be leaking, the first attempt at repair should be made within a reasonable period of time, such as no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

(1) Tightening of bonnet bolts,

(2) Replacement of bonnet bolts,

(3) Tightening of packing gland nuts, and

(4) Injection of lubricant into lubricated packing.

Once the equipment is repaired, it should be re-monitored over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair equipment is to replace the leaking equipment with a “leakless” equipment or other technologies.

When implementing an LDAR program, we recommend that air agencies consider including recordkeeping requirements that require owner/operators of subject facilities to maintain a list of identification numbers for all equipment subject to an equipment leak regulation. A list of equipment that is designated as “unsafe to monitor” should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.0 FUGITIVE EMISSIONS FROM WELL SITES AND GATHERING AND BOOSTING STATIONS

Fugitive emissions from components in the oil and natural gas industry are a source of VOC emissions. This chapter discusses the sources of fugitive emissions, and provides VOC emission estimates for well sites and gathering and boosting stations in the production segment (located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline). This chapter also presents a description of programs that are designed to reduce fugitive emissions, along with costs, and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the estimated VOC emission reductions and costs for fugitive emissions from well sites and gathering and boosting stations in the production segment.

9.1 Applicability

For purposes of this CTG, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at well sites with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents)[139] and the collection of fugitive emissions components at gathering and boosting stations in the production segment.

For the purposes of this CTG, fugitive emission reduction recommendations would not apply to well sites that only contain wellheads.

Fugitive emissions, for the purposes of applicability of this CTG, means those emissions from a stationary source that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Equipment leak emissions at natural gas processing plants are covered under chapter 8 of this document.

[139] Natural gas production converted to barrel equivalents uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet of natural gas. Based upon conversion factor used for the no longer in service U.S. EIA Financial Reporting System for Major Energy Producers.

9.2 Fugitive Emissions Description and Data

9.2.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas industry. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure, temperature, or mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves, or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission.

For the purposes of our RACT analysis for fugitive emissions from components and equipment, we differentiated between the definition of "equipment" for purposes of controlling equipment leaks for oil and natural gas processing plants in subpart OOOO[140] and the definition we use for the purposes of addressing fugitive emissions from oil and natural gas well sites and gathering and boosting stations. For purposes of our RACT analysis, "fugitive emissions component(s)" are the focus of our analysis for fugitive emissions from oil and natural gas well sites and gathering and boosting stations. The definition for "fugitive emissions component" is as follows:

> *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not already subject to equipment and fugitive emissions monitoring, thief hatches or other openings on a controlled storage vessel, compressors, instruments and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions

[140] The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

components, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

9.2.2. Emission Data and Emission Factors

9.2.2.1 Summary of Major Studies and Emission Factors

In April of 2014, we published a white paper[141] which summarized our current understanding of VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities (referred to herein as the "equipment leaks white paper"). The equipment leaks white paper also outlined our understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

The equipment leaks white paper provided a summary of fugitive emission studies at oil and natural gas well sites and gathering and boosting stations in the production segment. Throughout the development of this CTG, the EPA evaluated a variety of emissions data and emission reduction options for fugitive emissions. Many of the studies in the equipment leaks white paper were consulted. Table 9-1 presents a list of the studies consulted along with an indication of the type of information contained in each study.

Table 9-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[m]
Protocol for Equipment Leak Emission Estimates[a]	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks[b]	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program[c]	EPA	2013	Facility	X	
Inventory of Greenhouse Gas Emissions and Sinks[d]	EPA	Annual	Regional	X	
Measurements of Methane Emissions at Natural Gas	Multiple Affiliations,	2013	Nationwide	X	X

[141] U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[m]
Production Sites in the United States[e]	Academic and Private				
City of Fort Worth Natural Gas Air Quality Study, Final Report[f]	City of Fort Worth	2011	Fort Worth, TX	X	X
Measurements of Well Pad Emissions in Greeley, CO[g]	ARCADIS/Sage Environmental Consulting/ EPA	2012	Colorado	X	X
Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras[h]	Carbon Limits	2013	Canada and the U.S.	X	X
Mobile Measurement Studies in Colorado, Texas, and Wyoming[i]	EPA	2012 and 2014	Colorado, Texas, and Wyoming	X	X
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[j]	ICF International	2014	Nationwide	X	X
Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants[k]	Clearstone Engineering, Ltd.	2002	4 gas processing plants	X	X
Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites[l]	Clearstone Engineering, Ltd.	2006	5 gas processing plants, 12 well sites	X	X

[a] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.
[b] U.S. Environmental Protection Agency/GRI. Research and Development, *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).
[c] U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.
[d] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[e] Allen, David, T., et al. *Measurements of methane emissions at natural gas production sites in the United States*. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs.

[f] ERG and Sage Environmental Consulting, LP. *City of Fort Worth Natural Gas Air Quality Study, Final Report*. Prepared for the City of Fort Worth, Texas. July 13, 2011. Available at http://fortworthtexas.gov/gaswells/default.aspx?id=87074.
[g] Modrak, Mark T., et al. *Understanding Direct Emissions Measurement Approaches for Upstream Oil and Gas Production Operations. Air and Waste Management Association 105th Annual Conference and Exhibition*, June 19-22, 2012 in San Antonio, Texas.
[h] Carbon Limits. *Quantifying cost-effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras*. December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATF-Carbon_Limits_Leaks_Interim_Report.pdf.
[i] Thoma, Eben D., et al. *Assessment of Methane and VOC Emissions from Select Upstream Oil and Gas Production Operations Using Remote Measurements, Interim Report on Recent Studies. Proceedings of the 105th Annual Conference of the Air and Waste Management Association*, June 19-22, 2012 in San Antonio, Texas.
[j] ICF International. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S.* Onshore Oil and Natural Gas Industries. ICF International (Prepared for the Environmental Defense Fund). March 2014.
[k] Clearstone Engineering Ltd. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plan*ts. June, 2002.
[l] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. March 2006.
[m] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

9.2.2.2 Model Plants

Facilities in the oil and natural gas industry consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where "surface sites" can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce fugitive emissions from well sites and gathering and boosting stations, a model plant approach was used. The following sections discuss the creation of these model plants.

<u>Oil and Natural Gas Production Well Sites</u>

Oil and natural gas production varies from one site to the next. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well site. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation, and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Model plants were developed using the average number of wells associated with a well site using data from the Drillinginfo HPDI database.[142] Baseline fugitive emissions from well sites depend upon the quantity of equipment and components, which in turn is based on this estimate of wells per pad. To estimate the average number of wells co-located on the same site as a new well completion or recompletion, the EPA developed a pair of algorithms that identified new and existing wells within a given distance of a new well completion or recompletion. This distance was assumed to represent the distance that, if other wells were within the distance, the wells would likely be co-located with the well under examination on the same site. The algorithms were written in the open source R programming language.[143]

The HPDI well and production data used to estimate the average number of well co-located on a well site drew upon the latitude and longitude of new well completions and recompletions as well as the coordinates of all wells producing oil or natural gas in 2012. The first algorithm estimated the distances between each new completion and recompletion and all producing wells, which also includes wells newly completed and producing in 2012 within the same county as the completed well. If the distance between the completed well and producing well was less than the assumed size of a typical well site, we assumed the two wells were co-located. This algorithm progressed county by county across the U.S. where oil and natural gas production occurred in 2012 to identify all co-located wells in the U.S. The number of new well completions and recompletions in 2012 was about 44,000, which includes oil and natural gas wells whether they were hydraulically fractured or not. Wells producing in 2012 numbered about 1.27 million. The second algorithm processed the results of the first such that a well can only appear once on a modelled well site.

Once these algorithms were complete and produced a results file, we converted the results into a "kml" file that enabled the visual inspection of the results within Google Earth. We did not visually inspect every site in the U.S. linked to a 2012 completion or recompletion as

[142] Drilling Information, Inc. 2011. *DI Desktop.* 2011 Production Information Database.

[143] See the website <http://www.r-project.org/> for more information on R (The R Project for Statistical Computing). R is a free software environment for statistical computing and graphics.

they numbered greater than 20,000. Instead, we examined sites randomly across a range of oil and natural gas production regions. The results of this visual examination indicated the algorithms were functioning as intended.

We estimated the number of wells per site assuming sites of one, two and three acres, based upon input from petroleum industry data analysts. Table 9-2 shows the high-level results of these analyses.

Table 9-2. Estimated Average Number of Wells per Site of New Well Completion in 2012

Assumed Well Site Size	No. of Well Sites	No. of Wells at Sites	Average of Wells Per Site
One Acre	29,213	50,599	1.73
Two Acres	28,938	52,422	1.81
Three Acres	28,710	53,981	1.88

For assumed well sites of two acres, the analysis identified 28,938 independent well sites that contained 52,422 wells (including both single and multi-well sites). The total number of wells identified as being co-located with new well completions and recompletions exceeds the total number of completions and recompletions because the sites include about 8,500 existing wells producing in 2012.

However, the high level summary presented in Table 9-3 masks variation by basins and well types. Table 9-3 presents more detail along these dimensions for the assumed two-acre well site.

Table 9-3. Estimated Average Number of Wells per Two-Acre Site of New Well Completions and Recompletions in 2012, by HPDI Basin and Type of Well (Oil or Natural Gas, Hydraulically Fractured or Not)

HPDI Basin	No. Of Sites	Oil Well Completions HF	Oil Well Completions Not HF	Oil Well Completions All	Natural Gas Well Completions HF	Natural Gas Well Completions Not HF	Natural Gas Well Completions All	Total
Los Angeles	23	N/A	13.07	13.07	N/A	N/A	N/A	13.07
Piceance	111	2.00	1.00	1.75	6.72	11.75	10.14	9.84
Arctic Ocean	2	N/A	5.50	5.50	N/A	N/A	N/A	5.50
Green River	164	2.23	1.57	2.01	4.37	1.13	4.19	3.88
Unidentified	226	1.18	3.57	3.38	1.00	1.77	1.44	3.22
San Joaquin Basin	1,745	1.56	3.46	3.21	2.61	1.42	2.24	3.16
Arkoma Basin	374	4.00	1.33	2.00	3.06	1.00	3.01	3.00
Denver Julesburg	826	2.63	3.10	2.75	1.48	3.14	1.72	2.46
Ft. Worth Basin	1,305	2.05	1.86	1.91	3.27	1.10	2.93	2.33
Central Western Overthrust	7	1.50	N/A	1.50	2.60	N/A	2.60	2.29
Ventura Basin	1	N/A	2.00	2.00	N/A	N/A	N/A	2.00
Arctic Slope	42	N/A	2.13	2.13	N/A	1.65	1.65	1.99
Ouachita Folded Belt	181	2.01	1.90	1.99	1.50	1.00	1.43	1.97
Salina Basin	13	N/A	1.92	1.92	N/A	N/A	N/A	1.92
Palo Duro Basin	81	1.42	1.97	1.89	1.00	N/A	1.00	1.86
Uinta	548	1.16	1.33	1.32	N/A	3.33	3.33	1.83
Texas & Louisiana Gulf Coast	3,994	2.03	1.82	1.96	1.37	1.14	1.28	1.79
Central Kansas Uplift	450	N/A	1.78	1.78	N/A	1.53	1.53	1.77
Permian Basin	8,507	1.66	1.76	1.69	1.50	1.57	1.52	1.68
Sedgwick Basin	240	N/A	1.67	1.67	1.67	1.55	1.55	1.62
Las Animas Arch	25	1.00	1.64	1.61	N/A	1.50	1.50	1.60
Nemaha Anticline	38	N/A	1.55	1.55	N/A	N/A	N/A	1.55
Arkla Basin	811	1.09	1.57	1.49	1.47	1.09	1.42	1.46
Chautauqua Platform	461	1.36	1.57	1.49	1.64	1.03	1.35	1.45
Cook Inlet Basin	9	N/A	2.00	2.00	N/A	1.29	1.29	1.44
Appalachian	2,496	1.14	1.05	1.10	2.28	1.10	1.77	1.43
Williston	1,570	1.36	1.00	1.35	1.43	1.00	1.39	1.35
Cherokee Basin	271	1.17	1.29	1.29	N/A	1.69	1.69	1.35
San Juan	158	1.00	1.00	1.00	1.38	1.20	1.37	1.31
East Texas Basin	618	1.25	1.74	1.52	1.22	1.06	1.21	1.31
Forest City Basin	172	N/A	1.28	1.28	N/A	N/A	N/A	1.28
Anadarko Basin	2,663	1.17	1.77	1.37	1.09	1.29	1.13	1.27
South Oklahoma Folded Belt	167	1.17	1.36	1.30	1.11	1.11	1.11	1.24
Chadron Arch	49	N/A	1.22	1.22	N/A	N/A	N/A	1.22

HPDI Basin	No. Of Sites	Oil Well Completions HF	Oil Well Completions Not HF	Oil Well Completions All	Natural Gas Well Completions HF	Natural Gas Well Completions Not HF	Natural Gas Well Completions All	Total
Sacramento Basin	13	N/A	N/A	N/A	N/A	1.15	1.15	1.15
Mississippi & Alabama Gulf Coast	132	1.00	1.18	1.14	1.00	1.00	1.00	1.14
Central Montana Uplift	10	1.13	1.00	1.10	N/A	N/A	N/A	1.10
Big Horn	30	1.10	1.11	1.11	1.00	N/A	1.00	1.10
Powder River	232	1.15	1.03	1.12	1.05	1.00	1.04	1.10
Sweet Grass Arch	17	1.00	1.08	1.05	1.50	1.00	1.33	1.10
Paradox	13	1.00	1.10	1.09	1.00	N/A	1.00	1.08
Black Warrior Basin	57	1.00	1.00	1.00	1.00	1.75	1.07	1.05
Wind River	63	1.00	1.02	1.02	1.00	1.00	1.00	1.02
Wasatch Uplift	1	N/A	1.00	1.00	N/A	N/A	N/A	1.00
North Park	2	1.00	1.00	1.00	N/A	N/A	N/A	1.00
Raton	20	N/A	N/A	N/A	1.00	1.00	1.00	1.00
Grand Total	**28,938**	**1.64**	**1.99**	**1.79**	**1.90**	**1.76**	**1.86**	**1.81**

The data presented in Table 9-3 indicates that the concentration of wells at production sites varies greatly by basin. However, the analysis also indicates that most wells sites have relatively few or no co-located wells, which brings the national average of wells per new completion or recompletion site to 1.81 for the two-acre well site. While the analysis shows variation by basin, at the national level, there is relatively little variation across oil and natural gas well completion sites and whether the new wells were completed or recompleted using hydraulic fracturing. For example, oil well sites averaged 1.79 wells per site while natural gas wells averaged 1.86.

As a result of this analysis, we decided to use the two-acre well site as the assumed maximum size of a site to estimate the number of wells co-located at sites of new completions and recompletions. Also, to simplify analysis of costs and emissions at well sites, we rounded the 1.81 national average wells per site to 2.

While we are confident that the assumed two-acre well site is a reasonable size to capture most co-located wells in 2012, it is by no means a perfect assumption. First, industry and state regulatory trends indicate that well drilling will likely become increasingly concentrated on sites, potentially leading to an increase in the average number of wells per well site. However, it is not possible at this point to forecast this increasing concentration, especially with the variations by fields described above. Also, it is possible that two acres is too small to accurately estimate the number of co-located wells for large well sites in some fields. As a result, the algorithms might result in an underestimate of the average number of wells at a site and identify more than one site when in actuality there is only one. Alternatively, the assumed two acres might overestimate the size of sites in some fields and, as a result, pull in more than one site, overestimating the number of wells on the site. We also noted that the latitude and longitude values on many wells were likely incorrect or exact duplicates of other wells. Despite these caveats, we believe that the well site analysis described here produces a reasonable estimate of national average of number of wells on new well completion and recompletion sites in 2012. Therefore, based on this analysis, the model plants for oil and natural gas well sites are based on a well site with 2 wells.

Baseline model plant emissions for natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from the GHG Inventory, derived from GHGRP, EPA/GRI and 40 CFR part 98, subpart W tables, and the component oil and natural gas production emission factors from AP-42.[144] Annual emissions were calculated assuming 8,760 hours of operation each year. We used equipment count data from the EPA GHG Inventory to calculate the average counts of production equipment located at a well site. The types of production equipment located at a well site include: gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of components that are associated with these production equipment types include: valves, connectors, open-ended lines, and pressure relief valves. Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S. and the Western U.S. Fractions of components were rounded up to the nearest integer.

For natural gas well sites, the model plant was developed using the average equipment and fugitive emissions components counts for natural gas production data from the EPA/GRI report and the 2016 GHG Inventory. The average equipment count for a natural gas well was estimated by using the average equipment counts per well in the 2016 GHG Inventory (based on GHGRP data), and by weighing the average component counts per equipment for the Eastern and Western U.S. data sets for gas production equipment. This resulted in 2 separators, 3 meters/piping, 1 in-line heater, and 1 dehydrator per well. The total natural gas well site

[144] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Table 2-4. November 1995. EPA-453/R-95-017.

equipment counts were calculated by multiplying the average well equipment values by the average number of wells per well site (2), and rounding the product to the nearest integer. Average component counts for each of the equipment items were calculated using the average component counts for production equipment in the Eastern U.S. and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per equipment and rounding to the nearest integer. Table 9-4 presents a summary of the fugitive emissions component counts for natural gas well sites.

For oil well sites, two model plants were developed in order to account for emissions variability. One oil well model plant was developed for oil wells with a gas-to-oil ration less than 300 standard cubic feet of gas per stock barrel of oil (GOR less than 300) and another model plant was developed for oil wells with a gas-to-oil ratio greater than or equal to 300 standard cubic feet of gas per stock of barrel oil (GOR greater than or equal to 300).

The equipment count for the oil well model plant with a GOR less than 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater. These equipment counts were obtained from 2016 GHG Inventory data. The component counts for these equipment types were obtained from Table W-1C of subpart W and are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S.

The equipment count for the oil well model plant with a GOR greater than or equal to 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater and 3 meters/piping. These equipment counts for separators, headers, and heater/treaters were obtained from the 2016 GHG Inventory data for petroleum systems, while the meter/piping counts were obtained from the 2016 GHG Inventory data for natural gas systems to reflect gas production at the sites.

The component counts for these equipment types were obtained from Table W-1C of subpart W for all but meters/piping, which were obtained from Table W-1B of subpart W. The component counts are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S. The total number of fugitive emissions components for oil well sites equipment (for both model plants) was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. Table 9-5 presents a summary of the fugitive emissions component counts for oil well site model plants.

Table 9-4. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment[a]				Average Component Count per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
					Total	138.9	509.4	14.3	6.9
					Rounded up Total	139	510	15	7.0

[a] Data Source: EPA/GRI. *CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 9-5. Average Fugitive Emissions Component Count for Oil Well Site Model Plants

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment[a]					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR)[a]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
						Total	29	54	42	0	2
Oil Well Model Plant (≥ 300 GOR)[b]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
						Total	68	54	186	2	4

[a] Oil well (<300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Table W-1C.
[b] Oil well (≥300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Tables W-1B and W-1C.

The baseline emissions for the natural gas well site and oil well model plants were calculated using equipment counts for the natural gas well site model plant and the oil and natural gas production AP-42 total organic compound (TOC) emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to VOC using VOC/TOC weight rations in the 2011 Gas Composition Memorandum.[145]. The fugitive VOC emissions for the natural gas well site model plant were determined to be 1.53 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR less than 300 was determined to be 0.33 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR greater than or equal to 300 was determined to be 0.73 tpy of VOC. The VOC emission estimates were used to evaluate the potential emission reductions and cost of control of a fugitive emission reduction program. Table 9-6 presents the emission factors for the natural gas and oil production segments. A summary of the equipment counts, average TOC emission factors and VOC emissions for natural gas well and oil well sites are provided in Tables 9-7 and 9-8, respectively.

Table 9-6. Oil and Natural Gas Production Operations Average TOC Emission Factors

Component Type	Component Service	TOC Emission Factor[a] (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

[a] Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

[145] Memorandum to Bruce Moore from Heather Brown. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. EC/R, Incorporated. July, 2011.

Table 9-7. Estimated Fugitive VOC Emissions for Natural Gas Production Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled TOC Emission Factor[b] (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)[c]
Valves	139	0.0045	1.166
Connectors	510	0.0002	0.190
OELs	15	0.002	0.056
PRVs	7	0.0088	0.115
		Total	1.53

[a] Fugitive emissions component count values for model plant are based on a 2-wellhead site and are rounded to the nearest integer.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Table 9-8. Estimated Fugitive VOC Emissions for Oil Well Site Model Plants

Oil Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled Emission Factor[b] (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)[c]
Oil Well Model Plant (< 300 GOR)			
Valves	29	0.0045	0.243
Flanges	54	0.00039	0.039
Connectors	42	0.0002	0.016
OELs	0	0.002	0
PRVs	2	0.0088	0.033
		Total	0.33
Oil Well Model Plant (≥ 300 GOR)			
Valves	68	0.0045	0.571
Flanges	54	0.00039	0.039
Connectors	186	0.0002	0.069
OELs	2	0.002	0.007
PRVs	4	0.0088	0.066
		Total	0.75

[a] Fugitive emissions component count values for model plant are based on a 2-wellhead pad and are rounded to the nearest integer.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Gathering and Boosting Stations

Gathering and boosting stations are sites that collect natural gas from well sites and direct them to the natural gas processing plants. These stations have similar equipment to well sites; however they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in chapter 5 of this document. Table 9-9 presents a summary of the fugitive emissions component counts for oil and gas gathering and boosting stations.

Baseline emissions were calculated using the component counts and the TOC emission factors for oil and natural gas production (See Table 9-6). Table 9-10 summarizes the baseline emissions for gathering and boosting stations. The average fugitive emissions from a gathering and boosting station were determined to be 9.8 tpy of VOC. The VOC emission estimate was used to evaluate the potential emission reductions and cost of control of a fugitive emissions reduction program.

Table 9-9. Average Component Count for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment[a]				Average Component Count per Model Plant			
		Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
					Total	906	2,864	83	48

[a] Data Source: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Tables 4-4 and 4-7, June 1996. (EPA- 600/R-96-080h).

Table 9-10. Estimated Fugitive TOC and VOC Emissions for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Component	Model Plant Component Count[a]	Component TOC Emission Factor (kg/hr/ component)[b]	VOC Emissions (tons/yr)[c]
Valve	906	0.0045	7.6
Connectors	2,864	0.0002	1.1
OEL	83	0.002	0.3
PRV	48	0.0088	0.8
		Total	9.8

[a] Component counts from Table 9-9.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions are the baseline which were calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

9.3 Available Controls and Regulatory Approaches

9.3.1 Available VOC Emission Control Options

The EPA has determined that fugitive emissions from components are a significant source of VOC emissions from well sites and gathering and boosting stations. Based on the review of public and peer review comments on the equipment leaks white paper and the Colorado and Wyoming state rules, the EPA has identified two options for reducing fugitive VOC emissions from components: a fugitive emissions monitoring program based on the use of OGI leak detection combined with repair of fugitive emission components, and a leak monitoring program based on individual component monitoring using Method 21 for leak detection combined with repair of fugitive emission components. These options, as currently being used by industry to reduce fugitive emissions in the oil and natural gas industry, are described below.

9.3.1.1 Fugitive Emission Detection and Repair with Optical Gas Imaging

<u>Description</u>

The reduction of fugitive emissions from oil and natural gas well sites and gathering and boosting stations involves the development and implementation of a fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites or gathering and boosting stations. Under this option, monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company-defined area. An example monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

Control Effectiveness

Potential emission reduction percentages from the implementation of an OGI monitoring program varies from 40 to 99 percent.[146] The data supporting these emission reduction percentages are based on the gathering of individual OGI surveys at various oil and natural gas industry segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found (e.g., open thief hatches, open dump valves, etc.) during the OGI survey and assumptions made by the authors. However, the studies supporting these emission reduction percentages did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly, or monthly OGI monitoring and repair program. A report was found, after the publication of the white paper, from the Colorado Air Quality Control Commission,[147] which estimated (1) 40 percent reduction for annual OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy; (2) 60 percent reduction for quarterly OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy; and (3) 80 percent reduction for monthly OGI monitoring at well production tank batteries with uncontrolled VOC emissions greater than 50 tpy.

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, we expect the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado

[146] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks*, Office of Air Quality Planning and Standards. Research Triangle Park, NC. April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers.

[147] Colorado Air Quality Control Commission, *Cost-Benefit Analysis Submitted Per § 24-4-103(2.5), C.R.S. For Proposed Revisions to Colorado Air Quality Control Commission Regulations Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9).* February 7, 2014.

estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on information in the studies and EPA's engineering judgment, the potential emission reduction percentages are estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emission reductions for annual, semiannual and quarterly monitoring frequencies were calculated using the data from the EPA Protocol document.[148] For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500 ppm level, and achieves similar emission reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF[149] using data from subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers, and Jonah Energy LLC WCCA Spring Meeting Presentation determined the Year 3 fugitive emission reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semiannual and quarterly monitoring, respectively.

[148] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, *Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program*. April 25, 2016.
[149] ICF International. *Leak Detection and Repair Cost-Effectiveness Analysis*. Prepared for Environmental Defense Fund. December 4, 2015. Revised May 2, 2016.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency, as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emission reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emission reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.[150]

Cost Impacts

Costs (2012 dollars) for preparing an OGI emission monitoring and repair plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

(1) Labor cost for each of the monitoring plan elements was estimated to be $57.80 per hour.
(2) Reading of the rule and instructions would take one person four hours to complete at a cost of $231.
(3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of $3,468.
(4) Initial activities planning are estimated to take two people a total of 8 hours per monitoring event. Cost for annual monitoring was estimated to be $925, semiannual monitoring was estimated to be $1,850, and quarterly monitoring was estimated to be $3,699.
(5) Notification of compliance status was estimated to take one person one hour to complete at a cost of $58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be $58 per well site

[150] See Emission Reduction Comparison – Well Sites.xls, and Emission Reduction Comparison – Compressor Stations.xls in Docket Id. No. EPA-HQ-OAR-2015-0216 for more information.

for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.

(6) Cost of a Method 21 monitoring device of $10,800; or cost for OGI monitoring using an outside contractor (assumed to be $600 for a well site and $2,300 for a gathering and boosting station for each survey).

Costs for implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

(1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.

(2) The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well site and $2,300 for a gathering and boosting station for each survey.

(3) Annual repair costs were estimated to be $299 for well sites and $3,436 for gathering and boosting stations per survey. These costs were estimated assuming that 1.18 percent of the components leak and 75 percent are repaired online and 25 percent are repaired offline.

(4) Cost for resurvey of components assumes five minutes per leak at $57.80 per hour for well sites and $2.00 per leak for gathering and boosting stations. This is based on the assumption that a company purchases Method 21 instrumentation (estimated to be $10,800[151]) and is able to perform the resurvey without needing contractors.

(5) Preparation of annual reports was estimated to take one person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for well sites was calculated by summing up the costs for reading the air agency rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. The total capital cost of these activities was calculated to be $16,696 per company-defined areas for annual monitoring,

[151] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180.

$17,620 per company-defined areas for semiannual monitoring and $19,470 per company-defined areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area[152], the capital cost per well site was estimated to be $759 for annual monitoring, $801 for semiannual monitoring and $855 for quarterly monitoring. For gathering and boosting stations, the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation device was calculated to be $16,753 per facility. For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated seven gathering and boosting stations, and the capital cost for each of these stations was estimated to be $2,393.

For well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, OGI survey by an outside contractor, cost of repair of fugitive emissions found, preparation and submittal of an annual report and the amortized capital cost over 8 years at 7 percent interest. For our analyses, we calculated the annual cost for annual, semiannual and quarterly OGI surveys. The annual cost for annual, semiannual, and quarterly OGI surveying (inclusive of contractor costs, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for the production and processing segments. Tables 9-11 through 9-13 present summaries of the cost of control for VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly).

[152] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

Table 9-11. Summary of the Model Plant VOC Cost of Control for the Annual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy)[a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year)[c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	0.61	$759	$1,318	$809	$2,158	$1,324
Oil Well Site (GOR < 300)	0.13	$759	$1,318	$1,204	$9,953	$9,089
Oil Well Site (GOR $\geq$ 300)	0.30	$759	$1,318	$1,063	$4,380	$3,533
Gathering and Boosting Station	3.91	$2,393	$7,777	$4,518	$1,990	$1,156

[a] Assumes 40 percent reduction with the implementation of annual IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $1,191 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $7,736 and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-12. Summary of the Model Plant VOC Cost of Control for the Semiannual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	0.917	$801	$2,285	$1,521	$2,494	$1,660
Oil Well Site (GOR < 300)	0.199	$801	$2,285	$2,114	$11,503	$10,639
Oil Well Site (GOR $\geq$ 300)	0.451	$801	$2,285	$1,903	$5,062	$4,215
Gathering and Boosting Station	5.86	$2,393	$13,534	$8,646	$2,309	$1,475

[a] Assumes 60 percent reduction with the implementation of semiannual IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-13. Summary of the Model Plant VOC Cost of Control for the Quarterly OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	1.222	$885	$4,220	$3,201	$3,453	$2,619
Oil Well Site (GOR < 300)	0.265	$885	$4,220	$3,991	$15,929	$15,064
Oil Well Site (GOR ≥ 300)	0.602	$885	$4,220	$3,710	$7,010	$6,163
Gathering and Boosting Station	7.81	$2,393	$25,049	$18,532	$3,205	$2,371

[a] Assumes 80 percent reduction with the implementation of quarterly IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

9.3.1.2 Fugitive Emission Detection and Correction with Method 21

Description

Another option that can be used to reduce fugitive emissions from well sites and gathering and boosting stations involves the development of a fugitive emissions monitoring plan using Method 21 to detect leaks from equipment and components. The plan would incorporate surveying of components at a specified interval and repair threshold using a Method 21 instrument, which also includes following the Method 21 requirements for monitoring, along with repair, recordkeeping and reporting requirements.

The plan would also include provisions for repair or replacement of components if evidence of fugitive emissions are discovered during the survey. The monitoring plan would include inspection of all fugitive emission components and would require repair where evidence of fugitive emissions is discovered (as soon as practicable, but generally no later than 30 calendar days after the Method 21 survey). In addition, all repairs or replacement of components would be re-surveyed immediately after repair or replacement to ensure the fugitive emissions are below the specified repair threshold.

A facility can use a company-defined area fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations. By using a company-defined area, owners and operators have flexibility in developing monitoring plans and determining which company-defined area can be covered under the specifications outlined in one monitoring plan, for ease of implementation and compliance.

Control Effectiveness

Potential control efficiencies for Method 21 monitoring were estimated to be 42 to 83 percent depending on repair threshold and monitoring frequency in the 2016 NSPS. The Method 21 control options included repair thresholds of 10,000 and 500 parts per million (ppm) and annual, semiannual, and quarterly monitoring frequencies. Tables 9-14 through 9-16 present the summaries of the estimated emission reductions for annual, semiannual and quarterly Method 21 monitoring for the two repair thresholds for the well site and the gathering and boosting station model plants.

Cost Impacts

Costs (2012 dollars) for preparing and implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the plan elements. The costs are based on the following assumptions:

(1) Labor cost for each of the monitoring plan elements was estimated to be $57.80 per hour.
(2) Reading of the air agency rule and instructions would take one person four hours to complete at a cost of $231.20.
(3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of $3,468.
(4) Initial activities planning are estimated to take two people a total of 16 hours per monitoring event. Cost for annual monitoring was estimated to be $925, semiannual monitoring was estimated to be $1,850, and quarterly monitoring was estimated to be $3,699.

Table 9-14. Summary of the Model Plant VOC Cost of Control for the Annual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year)[c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	.645	$1,418	$2,300	$1,762	$3,568	$2,734
Oil Well Site (GOR < 300)	0.14	$1,418	$2,300	$2,179	$16,459	$15,595
Oil Well Site (GOR $\geq$ 300)	0.318	$1,418	$2,300	$2,031	$7,243	$6,396
Gathering and Boosting Station	4.12	$4,283	$9,803	$6,365	$2,378	$1,544
500 ppm Repair Threshold						
Natural Gas Well Site	1.043	$1,418	$2,300	1,430	$2,204	$1,371
Oil Well Site (GOR < 300)	0.226	$1,418	$2,300	$2,104	$10,169	$9,305
Oil Well Site (GOR $\geq$ 300)	0.514	$1,418	$2,300	$1,865	$4,475	$3,628
Gathering and Boosting Station	6.67	$4,283	$9,803	$4,239	$1,469	$635

[a] Assumes 42 percent reduction at 10,000 ppm repair threshold and 68 percent reduction at 500 ppm repair threshold with the implementation of annual Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-15. Summary of the Model Plant VOC Cost of Control for the Semiannual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	0.837	$1,460	$3,907	$3,209	$4,667	$3,833
Oil Well Site (GOR < 300)	0.181	$1,460	$3,907	$3,750	$21,530	$20,666
Oil Well Site (GOR ≥ 300)	0.412	$1,460	$3,907	$3,558	$9,475	$8,628
Gathering and Boosting Station	5.35	$4,415	$17,292	$12,828	$3,230	$2,396
500 ppm Repair Threshold						
Natural Gas Well Site	1.152	$1,460	$3,907	$2,946	$3,392	$2,558
Oil Well Site (GOR < 300)	0.250	$1,460	$3,907	$3,691	$15,648	$14,784
Oil Well Site (GOR ≥ 300)	0.567	$1,460	$3,907	$3,426	$6,887	$6,039
Gathering and Boosting Station	7.37	$4,415	$17,292	$11,150	$2,348	$1,514

[a] Assumes 55 percent reduction at 10,000 ppm repair threshold and 75 percent reduction at 500 ppm repair threshold with the implementation of semiannual Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program, which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-16. Summary of the Model Plant VOC Cost of Control for the Quarterly Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	1.030	$1,544	$7,121	$6,262	$6,196	$6,083
Oil Well Site (GOR < 300)	0.223	$1,544	$7,121	$6,928	$31,906	$31,042
Oil Well Site (GOR ≥ 300)	0.507	$1,544	$7,121	$6,691	$14,042	$13,195
Gathering and Boosting Station	6.58	$4,679	$32,271	$26,780	4,901	$4,067
500 ppm Repair Threshold						
Natural Gas Well Site	1.26	$1,544	$7,121	$6,070	$5,651	$4,817
Oil Well Site (GOR < 300)	0.273	$1,544	$7,121	$6,885	$26,067	$25,202
Oil Well Site (GOR ≥ 300)	0.621	$1,544	$7,121	$6,595	$11,472	$10,624
Gathering and Boosting Station	8.06	$4,679	$32,271	$25,550	$4,004	$3,170

[a] Assumes 67 percent reduction at 10,000 ppm repair threshold and 83 percent reduction at 500 ppm repair threshold with the implementation of quarterly Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites includes the cost of implementing the monitoring program of $32,120 divided by an average of 22 well sites per company.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

(5) Notification of compliance status was estimated to take one person one hour to complete at a cost of $58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be $58 per well site for each company-defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.

(6) Cost of a Method 21 monitoring device and data collection system was estimated at $25, 300 per company ($10,800 for the M21 monitoring device and $14,500 for the data collection system).

Costs for implementing a fugitive emission monitoring plan for a company-defined area for well sites and gathering and boosting stations were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

(1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.

(2) Method 21 monitoring was estimated to take two people a total of 16 hours to survey a well production site at a cost of $925 per survey. For gathering and boosting stations, Method 21 monitoring was estimated to take 2 people a total of 8 hours to survey the station at a cost of $925 per survey.

(3) Annual repair costs for well sites were estimated to be $299 using a repair threshold of 10,000 ppm and $5,400 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.

(4) Annual repair costs for gathering and boosting stations were estimated to be $3,436 using a repair threshold of 10,000 ppm and $52,900 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.

(5) Cost for resurvey of components assumes 5 minutes per leak at $57.80 per hour for well sites and $2.00 per leak for gathering and boosting stations.

(6) Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, acquisition of a Method 21 monitoring device and data collection system and notification of initial compliance status. The total capital cost of these activities was estimated to be $31,196 for annual monitoring, $32,120 for semiannual monitoring, and $33,970 for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area, the capital cost per well site was estimated to be $1,460.

For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210-mile radius of a central location, there would be an estimated seven gathering and boosting stations and the capital cost for these stations was estimated to be $29,982 for annual monitoring, $30,907 for semiannual monitoring, and $32,756 for quarterly monitoring. Assuming that there are 7 gathering and boosting stations in a company-defined area, the capital cost per station was estimated to be $4,283 for annual monitoring, $4,415 for semiannual monitoring, and $4,679 for quarterly monitoring.

For oil and natural gas well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. The annual cost for annual, semiannual, and quarterly Method 21 surveying (inclusive of cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for each of the industry segments. Tables 9-14 through 9-16 present summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000 and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual and quarterly).

9.3.2 Existing Federal, State and Local Regulations

9.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

For each well site and compressor station (including gathering and boosting stations), the EPA has finalized NSPS requirements that will require the development of a fugitive emissions monitoring plan that includes semiannual monitoring for well sites and quarterly monitoring for compressor stations by OGI and repair of leaking fugitive emission components. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.

9.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States or local air districts may have regulations or permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements. A summary of some of the existing state regulations and permit programs that apply to the oil and natural gas industry is provided below.

Colorado Regulation 7

The State of Colorado has regulations that require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels. For well production facilities and compressor stations, the monitoring frequency is determined by the estimated uncontrolled actual VOC emissions leak from the highest emitting tank or, if no tanks are present, the controlled actual emissions from all permanent equipment. The monitoring frequency for fugitives at well production facilities varies depending on emissions. There is a one-time inspection (0-6 tpy VOC), annual inspections (6-12 tpy VOC), quarterly inspections (12-20 tpy VOC w/o tanks, 12-50 w/ tanks), or monthly inspections (> 20 TPY VOC w/o tanks, > 50 tpy VOC w/ tanks). Monthly AVO inspections are also required for well production facilities that do one-time, annual, and quarterly monitoring. For compressor stations, the monitoring frequency is annual (0-12 tpy VOC), quarterly (12-50 tpy VOC), or monthly (> 50 tpy VOC). A leak is defined as hydrocarbon concentration greater than 500 ppm. These regulations allow OGI inspections, Method 21 or other "[d]ivision approved instrument based monitoring device or method" to detect leaks (Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7). The first attempt to repair leaks found during monitoring must be made no later than five working days after discovery, unless parts are unavailable or the equipment requires shutdown to complete repair. If parts are unavailable, they must be ordered promptly and the repair must be made within 15 working days of receipt of the parts. If a shutdown is required, the leak must be repaired during the next scheduled shutdown.

Wyoming Chapter 8

The Wyoming Department of Environmental Quality issued regulations in June 2015 for existing (as of January 1, 2014) PAD facility (location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location) and single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area[153]. The rule requires operators with fugitive emissions greater than or equal to 4 tons per year of VOC to develop and implement an LDAR protocol by January 1, 2017. Operators must monitor components (flanges, connectors (other than flanges), open-ended lines, pumps, valves, and "other" components listed in Table 2-4 of the EPA's Protocol for Equipment Leak Emissions Estimates) quarterly using a combination of Method 21, IR camera, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule. No specific repair timeframes are included in the regulation.

Utah General Approval Order

The Utah Department of Environmental Quality approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014[154]. This General Approval Order (GAO) requires LDAR for equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) based on annual throughput of crude oil and condensate. Annual inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 10,000 barrels or for sources that do not

[153] Wyoming regulations are available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.
[154] Utah regulations are available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.

have a crude oil or condensate storage tank onsite, and quarterly inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 25,000 barrels. For sources performing quarterly monitoring, provisions are provided for less frequent monitoring if no leaks are found during a year of monitoring. Repairs must be made within 15 days of finding a leak. A delay of repair is allowed if replacement parts are unavailable (must order parts within 5 days of detection and repair leak within 15 days after receipt of the parts) or technically infeasible to repair without a shutdown (shutdown must occur within 6 months of finding leak or operators must demonstrate emissions from shutdown would be greater than the uncontrolled leaking component).

The monitoring can be performed using Method 21, a tunable diode laser absorption spectroscopy (TDLAS) or an IR camera. A leak is defined as a reading of 500 ppm with Method 21 analyzer or TDLAS, or visible leak with IR camera.

Ohio General Permit

The Ohio EPA approved two types of general permits in May 2014 for oil and gas well site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT subpart HH)[155]. Each permittee is required to develop and implement an LDAR program for ancillary equipment (pumps, compressors, pressure relief devices, connectors, valves, flanges, vents, covers, any bypass in a closed vent system, and each storage vessel) that requires monitoring using a forward looking infrared (FLIR) camera or Method 21. Leak definitions vary depending on component (most are 500 or 10,000 ppm). Quarterly monitoring is required for the first year and varies after that depending on performance. Repairs must be made within 30 days of finding a leak but if leaks cannot be repaired within that time frame, the general permit references the delay of repair provisions allowed under NSPS subpart VVa.

Ohio has also proposed a general permit for natural gas compressor stations that have the potential to leak greater than 10 tons per year of VOC. The general permit requirements for

[155] Ohio regulations available at
http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf.
http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits.

compressor stations are similar to the LDAR requirements for oil and gas well site production operations. No emissions data were available for this LDAR program.

Pennsylvania General Permit 5 and Exemption Category No. 38

General Permit 5 is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are minor air contamination facilities[156]. Exemption Category No. 38 of the Air Quality Permit Exemption List applies to sources located at a well pad[157]. The general permit requires operators to conduct leak detection and repair programs monthly using AVO methods. Equipment to be monitored include: valves, flanges, connectors, storage vessels/storage tanks, and compressor seals. In addition, the general permit requires annual monitoring at wells and quarterly monitoring for compression and processing facilities. Operators must use a FLIR camera or approved device to detect gaseous hydrocarbons leaks. All leaks at production sites, compressor stations or processing facilities must be repaired within 15 days of finding the leak.

West Virginia Class II General Permit G70-B

General Permit G70-B is for natural gas production facilities[158]. The permit requires quarterly monitoring using AVO, Method 21 analyzers, IR cameras, or some combination. The AVO inspection shall include, but not be limited to, defects as visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. If a Method 21 analyzer is used, a leak (fugitive emissions of regulated air pollutants) is defined as no detectable emissions (less than 500 ppm). If an IR camera is used, no detectable emissions is defined as no visible leaks detected in accordance with U.S. EPA alternative IR camera work practices (40 CFR 60, subpart A). The first attempt at repair must be made within 5 calendar days of discovering the leak, and the final repair must be made within 15 calendar days of discovering the leak. No emissions data are available for this LDAR program.

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[156] Pennsylvania regulations are available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf.

[157] Pennsylvania regulations are available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.

[158] West Virginia regulations are available at http://www.dep.wv.gov/daq/permitting/Documents/G70-B%20Final/G70-B%20General%20Permit%20Signed2.pdf.

San Joaquin Valley Air Pollution Control District Rule 4409

The San Joaquin Valley Air Pollution Control District requires the development of an operator management plan that establishes inspection, replacement, re-inspection requirements, maintenance, repair periods and replacement retrofit requirements for components at light crude oil production facilities, natural gas production facilities and natural gas processing plants[159].

For manned facilities, the District requires owners and operators to audio-visually inspect for leaks daily and, for unmanned sites, the District requires owners and operators to audio-visually inspect for leaks weekly. Additionally, the District requires owners and operators to conduct inspections for leaks quarterly using Method 21. Leaks discovered are required to be repaired within two to seven days of discovery, depending on the magnitude of the leak. An extension of up to seven days is allowed if the leak is minor. Owners and operators are also allowed to apply for written approval to change the Method 21 monitoring inspection frequency from quarterly to annually if they meet specified criteria. Components at oil production facilities and gas production facilities that exclusively handle gas/vapor or liquid with a VOC content of 10 percent by weight or less are exempt from requirements.

9.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's equipment leaks white paper. Based on our evaluation of this data and information about existing regulations that control VOC emissions from oil and natural gas production sites, this CTG provides RACT recommendations for the collection of fugitive emission components at well sites with an average production of greater than 15 barrel equivalents per well per day, and gathering and boosting stations. At this time, this CTG does not include a RACT recommendation for well sites with an average production of less than 15 barrel equivalents per well per day. However, we encourage air agencies to consider site-specific data from these sources in their RACT analyses.

We further recommend that RACT be the implementation of a monitoring plan that includes semiannual monitoring for well sites with a GOR greater than or equal to 300 and quarterly monitoring for gathering and boosting stations using OGI or Method 21 and repair of

[159] San Joaquin Valley APCD regulations available at http://www.arb.ca.gov/drdb/sju/cur.htm.

components found to be leaking. The information currently available to EPA does not support applying the RACT recommendations related to fugitive monitoring contained in this chapter of the CTG to well sites with a GOR less than 300.

As discussed in section 9.3.2.2 of this chapter, some existing state and local regulations already require fugitive emissions monitoring of oil and natural gas production sites. The monitoring techniques listed in these requirements include the use of either Method 21 or OGI to locate fugitive emissions from equipment and components. In addition, peer review comments received on the equipment leaks white paper indicate that some companies are voluntarily monitoring their production sites using OGI to eliminate leaks from equipment. Monitoring and repair of equipment and components using OGI or Method 21 are the most viable methods for reducing fugitive emissions from equipment leaks in the production segment of the oil and natural gas industry.

Both Wyoming and Ohio require quarterly monitoring of components at production sites, and the cost of control per ton of VOC reduced is considered reasonable for OGI quarterly monitoring for natural gas well sites (about $3,450 per ton of VOC reduced). However, based on the information currently available regarding the necessary equipment, trained personnel and the planning necessary to implement a monitoring and repair program, we are concerned about the potential compliance burden that could be associated with quarterly monitoring of the large number of existing well sites. The VOC cost of control for semiannual monitoring using OGI was estimated to be $2,494 per ton of VOC reduced for natural gas well sites and $5,062 per ton of VOC reduced for oil wells sites with a GOR greater than or equal to 300.

We do not estimate that there would be a compliance burden associated with quarterly fugitive OGI monitoring at gathering and boosting stations because there are fewer existing gathering and boosting stations than well sites. Moreover, the cost of control per ton of VOC reduced is reasonable for quarterly OGI monitoring. The VOC cost of control for quarterly monitoring using OGI was estimated to be about $3,200 per ton of VOC reduced for gathering and boosting stations.

For well sites, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is generally more costly than the use of OGI where there are a large number of equipment components to be monitored. The cost for a natural gas well site was estimated to be $4,667 per ton of VOC reduced for semiannual monitoring. The cost for an oil well site with a

GOR greater than 300 was estimated to be $9,475 per ton of VOC reduced for semiannual monitoring. As shown in section 9.3.1 of this chapter, the cost of control for the 500 ppm repair threshold options are higher than the 10,000 ppm repair threshold option. The use of a monitoring plan using Method 21 with a 10,000 ppm leak detection may, however, be a lower cost alternative to OGI where there are fewer equipment components to be monitored. For gathering and boosting stations, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is estimated to be $3,230 per ton of VOC reduced for semiannual monitoring and $3,205 for quarterly monitoring. The costs for semiannual monitoring using Method 21 for natural gas well sites, and quarterly monitoring using Method 21 for gathering and boosting stations were considered reasonable (about $4,670 for gas well sites and $3,200 for gathering and boosting stations). Based on our analyses that indicates that a monitoring plan using Method 21 at 500 ppm would meet the same level of control as semiannual monitoring using OGI, we recommend that air agencies allow owners and operators to comply by using Method 21 at 500 ppm as an alternative to semiannual monitoring using OGI.

Based on existing state and local fugitive emission requirements, economic feasibility, and the reasonableness of costs, we recommend that RACT for the collection of fugitive emission components at well sites with a GOR greater than or equal to 300 that produce, on average, greater than 15 barrel equivalents per well per day, be the implementation of a fugitive emissions monitoring and repair plan that includes semiannual monitoring using OGI or Method 21. For these same reasons, we recommend that RACT for the collection of fugitive emission components at gathering and boosting stations be the implementation of a fugitive emissions monitoring and repair plan that includes quarterly monitoring using OGI or Method 21.

In summary, we recommend the following RACT for the collection of fugitive emission components at well sites and gathering and boosting stations in the production segment:

(1) <u>RACT for the Collection of Fugitive Emission Components at Well Sites With a GOR Greater than or Equal to 300, that Produce, on Average, Greater than 15 Barrel Equivalents per Well per Day</u>: We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites. We further recommend that air agencies allow Method 21 with a repair threshold of 500 ppm as an alternative compliance means to OGI. We also

recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

(2) RACT for the Collection of Fugitive Emission Components at Gathering and Boosting Stations in the Production Segment (Located from the Wellhead to the Point of Custody Transfer to the Natural Gas Transmission and Storage Segment or Oil Pipeline): We recommend the implementation of a monitoring plan that includes quarterly monitoring using OGI and repair of components that are found to be leaking at gathering and boosting stations. We further recommend allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We also recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

9.5 Factors to Consider in Developing Fugitive Emissions RACT Procedures

To ensure that fugitive emissions are properly monitored and repaired (as necessary) under the RACT recommendations, we suggest that air agencies specify OGI/Method 21 monitoring and equipment repair recordkeeping and reporting requirements to document compliance. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.5.1 Monitoring Recommendations

We recommend that air agencies require a fugitive emissions OGI/Method 21 monitoring plan that covers fugitive emission component sources that includes basic required monitoring plan elements. We recommend that air agencies require the monitoring plan be developed for a company-defined area and that it cover the collection of fugitive emissions components at well sites and gathering and boosting stations.

We suggest that the fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and gathering and boosting stations within each company-defined area include the following minimum elements:

(1) Frequency for conducting surveys.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using OGI, you should also include the following: (i) Verification that your optical gas imaging equipment meets specification requirements (i.e., capable of imaging gases in a spectral range for the compound of highest concentration in the potential fugitive emissions, must be capable of imaging a gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 g/hr from a quarter inch diameter); (ii) Procedure for a daily verification check; (iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained; (iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold; (v) Procedures for conducting surveys; (vi) Training and experience needed prior to performing surveys; including how the operator will (a) ensure an adequate thermal background is present in order to view potential fugitive emissions, (b) deal with adverse monitoring conditions such as wind, (c) deal with interferences; and (vii) Procedures for calibration and maintenance.

(8) Procedures for calibration and maintenance should comply with those recommended by the manufacturer of monitoring device used.

(9) If you are using Method 21 of appendix A-7 of part 60, you should also include the following: (i) Verification that your monitoring equipment meets the requirements specified in section 6.0 of Method 21 at 40 CFR part 60, appendix A-7; and (ii) procedures for conducting surveys.

We suggest that you also require the following minimum elements in each fugitive emissions monitoring plan:

(1) Sitemap.

(2) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using Method 21, the plan should also include a list of fugitive emission components to be monitored and method for determining location of fugitive emission components to be monitored in the field (e.g., tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan should also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor and unsafe-to-monitor.

We recommend a monitoring survey of each collection of fugitive emissions components at a well site be conducted semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend a monitoring survey of each collection of fugitive emissions components at a gathering and boosting station be conducted quarterly after the initial survey and that consecutive quarterly monitoring surveys be conducted at least two months apart.

9.5.2 Repair Recommendations

We recommend that air agencies require that any identified source of fugitive emissions identified by using OGI (indicated by visual emissions) or Method 21 instrument (indicated by a concentration of 500 ppm above background) be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. We also recommend that repaired or replaced fugitive emission components be required to be resurveyed as soon as practicable, but no later than 30 days after completion of the repair or replacement, to ensure that there is no leak. For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, we recommend that air agencies require that the operator resurvey the repaired fugitive emissions components using Method 21 (or alternative screening procedure based on soap bubble solution method (as specified under section 8.3.3 of Method 21)), or OGI no later than 30 days of being repaired. A fugitive emissions component is repaired when either the Method 21 instrument indicates a concentration of less than 500 ppm above background, or an OGI instrument shows no indication of visible emissions.

Appendix

We include model rule language in this appendix for our recommended RACT for oil and natural gas industry sources. The intent of this language is to provide regulation language that states can use as a starting point in the development of their SIP. In some cases, the language may need to be revised to make it adequate for SIP approval purposes. Although we include model rule language for closed vent systems, control devices and performance tests (that apply across several model rule requirements for sources), it is acknowledged that states may have existing similar language in their programs that they may want to use in lieu of the model language provided. State implementation plans should specify enforceable test methods.

The model rule language does not specify rule compliance dates. These dates will be determined by air agencies (referred to within the model rule language as the “regulatory authority”). State and local government agencies are encouraged to search this model rule language for places where the “regulatory authority” will need to specify dates (e.g., compliance date) by searching for (“regulatory authority”) in the model rule language.

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A Storage Vessels: VOC Emission Control Requirements

A.1 Applicability

(a) The VOC emissions control requirements of section A apply to each storage vessel located in the oil and natural gas industry (excluding distribution) that has the potential for VOC emissions equal to or greater than 6 tpy. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. Any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining applicability, provided you comply with the requirements in section A.1(a)(i) through (a)(iv).

(i) You meet the cover requirements specified in section A.2(c).

(ii) You meet the closed vent system requirements specified in section A.2(d).

(iii) You must maintain records that document compliance with paragraphs A.2(c) and (d).

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs A.2(c) and (d) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(b) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel.

(c) The storage vessel VOC emission control requirements specified in this section do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

A.2 What VOC Emission Control Requirements Apply to Storage Vessels?

For each storage vessel, you must comply with the VOC emission control requirements of paragraphs (a) through (e) in this section by the compliance date established by your regulatory authority. Alternative requirements for storage vessels subject to VOC emission control requirements that meet certain conditions are presented in paragraph (i) of this section. Requirements for storage vessels removed from service are presented in paragraph (j) of this section.

(a) You must reduce VOC emissions from each storage vessel by 95.0 percent, unless you meet the conditions of paragraph (i) of this section.

(b) (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of paragraph (c) of this section, that is connected through a closed vent system that meets the requirements of paragraph (d) of this section and route to a control device that meets the conditions specified in paragraph (e) of this section, as applicable. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of 40 CFR 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Cover requirements for storage vessels.* (1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system, designed and operated in accordance with the requirements of paragraph (d) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(d) *Closed vent system requirements for storage vessels*. For closed vent system requirements using a control device or routing emissions to a process, you must comply with the following:

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device or to a process that meets the requirements specified in paragraph (e) of this section, or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

(3) You must meet the requirements specified in paragraph (d)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (d)(3)(ii) of this section, you must comply with either paragraph (d)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section A.5(a)(9).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (d)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device or to a process and that the control device is of sufficient design and capacity to accommodate all emissions from the storage vessel and have it certified by a qualified professional engineer in accordance with paragraphs (d)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (d)(4)(i) of this section.

(e) *Control device requirements for storage vessels*.

(1) Each control device used to meet the emission reduction standard in paragraph (a) of this section for your storage vessel must be installed according to paragraphs (e)(1)(i) through (iv) of this section, as applicable. As an alternative to paragraph (e)(1)(i) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e).

(i) For each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must follow the requirements in paragraphs (e)(1)(i)(A) through (D) of this section.

(A) Ensure that each enclosed combustion device is maintained in a leak free condition.

(B) Install and operate a continuous burning pilot flame.

(C) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in this paragraph.

(D) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (*1*) through (*4*) of this section.

(*1*) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b).

(*2*) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b).

(*3*) You must operate at a minimum temperature of 760°Celsius, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(*4*) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(ii) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(iii) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(iv) You must operate each control device used to comply with paragraph (a) of this section at all times when gases, vapors, and fumes are vented from the storage vessel through the closed vent system to the control device. You may vent more than one storage vessel to a control device used to comply with this subpart.

(2) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (e)(2)(i) and (ii) of this section.

(i) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (e)(1)(ii) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in section A.5(a)(10).

(ii) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (e)(2)(ii)(A) through (F) of this section.

(A) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(C) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(D) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(E) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(F) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(f) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each storage vessel as required in section A.3.

(g) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each storage vessel as required by section A.4.

(h) You must perform the required recordkeeping and reporting as required by section A.5.

(i) *Alternative requirements for storage vessels*. Maintain the uncontrolled actual VOC emissions from the storage vessel subject to VOC emission control requirements at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (i)(1) or (2) of this section.

(1) If a well feeding the storage vessel subject to VOC emission control requirements undergoes fracturing or refracturing, you must comply with paragraph (a) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel.

(2) If the monthly emissions determination required in this paragraph indicates that VOC emissions from your storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, you must comply with paragraph (a) of this section within 30 days of the monthly calculation.

(j) *Requirements for storage vessels that are removed from service or returned to service.* If you are the owner or operator of a storage vessel subject to the VOC emission control requirements that is removed from service, you must comply with paragraphs (j)(1) and (2) of this section. A storage vessel is not an affected source under this section for the period that it is removed from service.

(1) For a storage vessel to be removed from service, you must comply with the requirements of paragraph (j)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification in your next annual report, identifying each storage vessel removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel subject to VOC emission control requirements identified in paragraph (j)(1) of this section is returned to service during the reporting year, you must submit a notification in your next annual report identifying each storage vessel that has been returned to service and the date of its return to service.

A.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each storage vessel complying with section A.2 by complying with the requirements in paragraphs (a) through (h) of this section.

(a) You determine the potential VOC emission rate as specified in section A.1(a).

(b) You reduce VOC emissions from each storage vessel subject to VOC emission control requirements by 95.0 percent or greater as required in section A.2 and as demonstrated by section F.

(c) If you use a control device to reduce emissions, you must equip your storage vessel with a cover that meets the requirements of section A.2(c) that is connected through a closed vent system that meets the requirements of section A.2(d) and is routed to a control device that meets the requirements of A.2(e). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(d) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(e) You conduct the initial cover and closed vent system inspections according to the requirements in section A.4(d) within 180 days after the compliance date established by your regulatory authority.

(f) You submit the initial annual report for your storage vessels as required in section A.5(b).

(g) You maintain the records as specified in section A.5(a).

(h) If you comply by using a floating roof, you submit a statement that you are complying with 40 CFR 60.112b(a)(1) or (2) in accordance with section A.2(b)(2) with the initial annual report specified in section A.5(b).

A.4 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each storage vessel subject to the VOC emission control requirements in section A.2 by meeting the requirements in paragraphs (a) through (f) of this section.

(a) For each storage vessel subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b) and (c) of this section.

(b) You must reduce VOC emissions from the storage vessel by 95.0 percent or greater.

(c) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section A.2(e) according to paragraphs (c)(1) through (4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with sections F(d)(2) through (10), which meets the criteria in section F(d)(11), the reporting requirements in section F(d)(12), and the continuous compliance requirements in F(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (c)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (c)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices

for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified by A.5(a)(11).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in section F(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

(d) If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (d)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (d)(2) of this section, and inspect each bypass device according to the procedures of paragraph (d)(3) of this section. You must also comply with the requirements of (d)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (d)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(8).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in section A.2(d)(3)(ii), you must meet the requirements of paragraphs (d)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to section A.5(a)(9).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to section A.5(a)(9).

(4) *Repairs*. In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (d)(4)(i) through (iii) of this section, except as provided in paragraph (d)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair*. Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements*. You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (d)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (d)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements*. You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (d)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(e) You must submit the annual reports for your storage vessels as required in section A.5(b).

(f) You must maintain the records as specified in section A.5(a).

A.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* For each storage vessel, you must maintain the records identified in paragraphs (a)(1) through (12) of this section, as applicable, either onsite or at the nearest local field office for at least five years.

(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and sections A.4(d)(6)(ii) and A.4(d)(7)(ii), as applicable.

(2) Records of each VOC emissions determination for each storage vessel made under A.1(a) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(3) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in sections A.2 and F, as applicable.

(4) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, must be added to the count towards the number of consecutive days.

(5) Records of the identification and location of each storage vessel subject to emission control requirements.

(6) Except as specified in paragraph (a)(6)(vii) of this section, you must maintain the records specified in paragraphs (a)(6)(i) through (vi) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous

compliance requirements in section F(d) (e) and used to comply with section A.2(a) for each storage vessel.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(6)(vi)(A) through (E).

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(E) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) As an alternative to the requirements of paragraph (a)(6)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(7) Records of each closed vent system inspection required under section A.4(d)(1)(i).

(8) A record of each cover inspection required under section A.4(d)(2)(i).

(9) If you are subject to the bypass requirements of section A.4(d)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(10) For each carbon adsorber installed on a storage vessel, records of the schedule for carbon replacement (as determined by the design analysis requirements of section E.1(a)(2)) and records of each carbon replacement as specified in section E.1(c)(1).

(11) For each storage vessel subject to the control device requirements of section E.2(c) and (d), records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in section E.2(h). Records of section 11, EPA Method 22, 40 CFR part 60, appendix A-7 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A-7. Control device manufacturer operating instructions, procedures and maintenance schedule must be available for inspection.

(12) A log of records as specified in sections A.2(e)(1)(i)(C) and F(e)(4), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(b) *Reporting requirements*. For storage vessels, you must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section.

(1) An identification, including the location, of each storage vessel subject to VOC emission control requirements. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(2) Documentation of the VOC emission rate determination according to section A.1(a).

(3) Records of deviations specified in paragraph (a)(3) of this section that occurred during the reporting period.

(4) A statement that you have met the requirements specified in section A.3(b) and (c).

(5) You must identify each storage vessel that is removed from service during the reporting period as specified in section A.2(j)(1), including the date the storage vessel was removed from service.

(6) You must identify each storage vessel returned to service during the reporting period as specified in section A.2(j)(3), including the date the storage vessel was returned to service.

A.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified professional engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Removed from service means that a storage vessel subject to the VOC control requirements has been physically isolated and disconnected from the process for a purpose other than maintenance.

Returned to service means that a storage vessel subject to the VOC requirements that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel subject to the VOC requirements; or

(2) Installed in any location covered by this rule and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered for beneficial use.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of section A.2(j)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this rule, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by section A.5(a)(4), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.

B Pneumatic Controllers: VOC Emission Control Requirements

B.1 Applicability

The VOC emission control requirements specified in section B.2 apply to the pneumatic controllers specified in paragraphs (a) and (b) of this section.

(a) For natural gas processing plants, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller.

(b) At locations from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

B.2 What VOC Emission Control Requirements Apply to Pneumatic Controllers?

For each pneumatic controller, you must comply with requirements for VOC, as specified in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from these requirements.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required based on functional needs including, but not limited to, response time, safety and positive actuation. However, you must tag such pneumatic controller with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller, as required in section B.5(a)(2).

(b)(1) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant, as defined in section B.1(a), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller as required in section B.5(a)(3).

(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline, as defined in section B.1(b), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a).

(d) You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission reduction requirements that apply to pneumatic controllers as required by section B.3.

(e) You must demonstrate continuous compliance with VOC emission reduction requirements that apply to pneumatic controllers as required by section B.4.

(f) You must perform the required recordkeeping as required by B.5(a) and reporting as required by section B.5(b).

B.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for your pneumatic controller by complying with the requirements specified in paragraphs (a) through (f) of this section by the compliance date established by your regulatory authority, as applicable.

(a) You must demonstrate initial compliance by maintaining records as specified in section B.5(a)(2) of your determination that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required as specified in section B.2(a).

(b) You own or operate a pneumatic controller located at a natural gas processing plant and your pneumatic controller is a non-natural gas-driven pneumatic controller that emits zero natural gas and VOC.

(c) You own or operate a pneumatic controller located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(d) You must tag each pneumatic controller according to the requirements of section B.2(b)(2) or (c)(2).

(e) You must include the information in paragraph (a) of this section and a listing of the pneumatic controller sources specified in paragraphs (b) and (c) of this section in the initial annual report according to the requirements of section B.5(b)

(f) You must maintain the records as specified in section B.5(a) for each pneumatic controller subject to VOC emission control requirements.

B.4 Continuous Compliance Demonstration Requirements

For each pneumatic controller, you must demonstrate continuous compliance according to paragraphs (a) through (c) of this section.

(a) You must continuously operate each pneumatic controller as required in section B.2(a), (b), or (c).

(b) You must submit the annual reports as required in section B.5(b).

(c) You must maintain records as required in section B.5(a).

B.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*. For each pneumatic controller, you must maintain the records identified in paragraphs (a)(1) through (4) of this section onsite or at the nearest local field office for at least five years.

(1) Records of the date, location and manufacturer specifications for each pneumatic controller.

(2) If applicable, a record of the demonstration that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(4) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in section B.2.

(b) *Reporting requirements*. You must submit annual reports containing the information specified in paragraphs (b)(1) through (3) of this section.

(1) An identification of each existing pneumatic controller, including the identification information specified in section B.2(b)(2) or (c)(2).

(2) If applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) Records of deviations specified in paragraph (a)(4) of this section that occurred during the reporting period.

B.6 Definitions

<u>*Bleed rate*</u> means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Underground storage vessel means a storage vessel stored below ground

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

C Compressors: VOC Emissions Control Requirements

C.1 Applicability

(a) *Centrifugal compressors*. Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

C.2 What VOC Emission Control Requirements Apply to Centrifugal Compressors?

For each centrifugal compressor, you must comply with the VOC emissions control requirements in paragraphs (a) through (g).

(a) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(b) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of section D.1(a)(1). The cover must be connected through a closed vent system that meets the requirements of section D.1(b) and the closed vent system must be routed to a control device that meets the conditions specified in paragraph (d) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) For each control device used to comply with the VOC emission reduction control requirements in paragraph (a), you must install and operate a continuous parameter monitoring system for each control device as specified in section E.2(a) through (f), except as provided for in section E.2(b).

(d) You must operate each control device installed on your centrifugal compressor in accordance with the requirements specified in paragraphs (d)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. You may vent more than one source to a single control device.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (f), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2), as applicable.

(e) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each centrifugal compressor as required by section C.4(a).

(f) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each centrifugal compressor as required by section C.5(a).

(g) You must perform the required recordkeeping and reporting as required by section C.6(a)(1) and (b)(1), as applicable.

C.3 What VOC Emission Control Requirements Apply to Reciprocating Compressors?

You must comply with the VOC emission control requirements in paragraphs (a) through (d) of this section for each reciprocating compressor.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning on the compliance date for your

reciprocating compressor as established by your regulatory authority, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the compliance date for a reciprocating compressor for which the rod packing has not yet been replaced.

(3) Route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b).

(b) You must demonstrate initial compliance with requirements that apply to reciprocating compressor sources as required by section C.4(b).

(c) You must demonstrate continuous compliance with requirements that apply to reciprocating compressor sources as required by section C.5(b).

(d) You must perform the required recordkeeping and reporting as required by section C.6(a)(2) and (b)(2).

C.4 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each centrifugal compressor by complying with the requirements in paragraph (a) of this section, and for each reciprocating compressor by complying with the requirements in paragraph (b) of this section.

(a) *Centrifugal compressors*. You have achieved initial compliance with the VOC emission control requirements for each centrifugal compressor if you have complied with paragraphs (a)(1) through (7) of this section.

(1) You reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required in section C.2(a) and as demonstrated by section F.

(2) You use a control device to reduce emissions, and you equip the wet seal fluid degassing system with a cover that meet the requirements of section D.1(a) that is connected through a closed vent system that meets the requirements of section D.1(b) and is routed to a control device that meets the requirements of section E.1. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(4) You conduct the initial cover and closed vent system inspections required in section D.2 within 180 days after the compliance date established by your regulatory authority.

(5) You install and operate the continuous parameter monitoring systems in accordance with section E.2(a) through (g).

(6) You submit the initial annual report for your centrifugal compressor as required in section C.6(b)(1).

(7) You maintain the records as specified in section C.6(a)(1).

(b) *Reciprocating compressors*. You have achieved initial compliance with the VOC emission control requirements for each reciprocating compressor if you have complied with paragraphs (b)(1) through (4) of this section.

(1) If complying with section C.3(a)(1) and (2), you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement, beginning on the compliance date established by your regulatory authority.

(2) If complying with section C.3(a)(3), you must route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b) by the compliance date established by your regulatory authority.

(3) You must submit the initial annual report for your reciprocating compressor as required in section C.6(b)(2).

(4) You maintain the records as specified in section C.6(a)(2).

C.5 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each centrifugal compressor by complying with the requirements of paragraph (a), and for each reciprocating compressor by complying with the requirements of paragraph (b).

(a) *Centrifugal compressors*. For each centrifugal compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (a)(1) through (4) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section C.2(a) using the procedures specified in paragraphs (a)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in section C.2(a), you may demonstrate compliance according to paragraph (a)(2)(viii) of this section. You may switch between compliance with paragraphs (a)(2)(i) through (vii) of this section and compliance with paragraph (a)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of section E.2(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with section E.2(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (a)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (a)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in section F(d), compliance with the operating parameter limit is achieved when the criteria in section F(e) are met.

(iv) You must operate the continuous monitoring system required in section E.2(a) at all times the source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of section C.2(a) and you demonstrate compliance using the test procedures specified in section F(b), or you use a flare designed and operated in accordance with 40 CFR 60.18(b), you must comply with paragraphs (a)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. A visible emissions test using section 11 of Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (a)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in section C.2(a)(1), you must demonstrate compliance using the procedures in paragraphs (a)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to section E.2(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with section E.2(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (a)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (a)(2)(viii)(A) of this section.

(D) You must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (a)(2)(viii)(C) of this section.

(1) If you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(2) After 120 days and no more than 364 days of operation, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days of operation where you have data. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (a)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by section C.6(b)(1) and maintain the records as specified in section C.6(a)(1).

(4) If you comply with this rule by equipping the wet seal fluid degassing system and route emissions to a control device or process as required by section C.2(b), you must comply with the cover and closed vent requirements in section D.1(a) and (b).

(b) *Reciprocating compressors*. For each reciprocating compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b)(1) through (4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor or track the number of months or the date of the most recent reciprocating compressor rod packing replacement.

(2) You must submit the annual reports as required in section C.6(b)(2) and maintain records as required in section C.6(a)(2).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) If you comply with this rule by collecting and routing VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure as required by section C.3(a)(3), you must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent system requirements in section D.1(b).

C.6 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*.

(1) *Centrifugal compressors*. For each centrifugal compressor, you must maintain records of the information specified in paragraphs (a)(1)(i) and (ii) of this section, and, if required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (ix) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations where the centrifugal compressor was not operated in compliance with requirements specified in section C.2. Except as specified in paragraph (a)(1)(ii)(G) of this section, you must maintain the records in paragraphs (a)(1)(ii)(A) through (F) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets continuous compliance requirements in section F(e) and used to comply with section C.2(a) for each centrifugal compressor.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(1)(ii)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(*5*) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) As an alternative to the requirements of paragraph (a)(1)(ii)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(iii) Records of each closed vent system inspection required under section D.2(a) and (b).

(iv) A record of each cover inspection required under section D.2(c).

(v) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(vi) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(vii) For each centrifugal compressor, records of the schedule for carbon replacement (as determined by the design analysis requirements of section F(c)(2) or (3)) and records of each carbon replacement as specified in section E.1(c)(1).

(viii) For each centrifugal compressor subject to the control device requirements of section E.1, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(ix) A log of records for all inspection, repair and maintenance activities for each control device failing the visible emissions test as specified in section C.5(a)(2)(vii)(C).

(2) *Reciprocating compressors*. For each reciprocating compressor VOC emissions source, you must maintain the records in paragraphs (a)(2)(i) through (iv) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) Records of the cumulative number of hours of operation or number of months since the previous replacement of the reciprocating compressor rod packing. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in section C.3(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in section C.3.

(iv) If you comply by routing emissions from the rod packing to a process through a closed vent system under negative pressure. You must maintain the records in paragraphs (a)(2)(iv)(A) through (D) of this section.

(A) Records of each closed vent system inspection required under section D.2(a) and (b).

(B) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(C) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(D) A record of each cover inspection required under section D.2(c).

(b) *Reporting requirements*.

(1) *Centrifugal compressors*. For each centrifugal compressor, you must submit annual reports containing the information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (viii) of this section.

(iv) If complying with C.2(a) with a control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e), in the initial annual report, records specified in paragraphs (a)(1)(ii)(A) through (a)(1)(ii)(G) of this section for each centrifugal compressor using a wet seal system that is subject to this rule. In subsequent annual reports, records specified in paragraph (a)(1)(ii)(F) of this section along with information sufficient to link to the identifying information provided in the initial report.

(2) *Reciprocating compressors*. For each reciprocating compressor, you must submit annual reports containing the information specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since the compliance date, or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of deviations specified in paragraph (a)(2)(iii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.3(a)(3), the records specified in paragraphs (a)(2)(i) through (iv) of this section.

C.7 Definitions

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low-pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this rule.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of this rule.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

D Cover and Closed Vent System Requirements

[Note: These requirements would not apply to covers and closed vent systems used on storage vessels.]

D.1 What Are My Cover and Closed Vent System Requirements?

You must meet the applicable requirements of this section for each cover and closed vent system where VOC emissions are routed to a control device or to a process.

(a) *Cover requirements*.

(1) <u>Centrifugal compressor cover requirements</u>.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a control device or to a process.

(2) <u>Reciprocating compressor cover requirements</u>.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the rod packing emissions collection system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a process.

(b) *Closed vent system requirements*.

(1) (i) <u>Centrifugal compressors</u>. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a control device or to a process. For centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in section E.1(a) through (c).

(ii) <u>Reciprocating compressors</u>. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a process.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by section D.2(e).

(3) You must meet the requirements specified in paragraph (b)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or process.

(i) Except as provided in paragraph (b)(3)(ii) of this section, you must comply with either paragraph (b)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in section D.2(d)(1) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (b)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the emission source are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the emission source and have it certified by a qualified professional engineer in accordance with paragraphs (b)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (b)(4)(i) of this section.

D.2 What Are My Initial and Continuous Cover and Closed Vent System Inspection and Monitoring Requirements?

Except as provided in paragraphs (e)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a) and (b) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c) of this section, and inspect each bypass device according to the procedures of paragraph (d) of this section.

(a) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1) and (2) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (e) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or the connection is unsealed. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(b) For closed vent system components other than those specified in paragraph (a) of this section, you must meet the requirements of paragraphs (b)(1) through (3) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions by the date established by your regulatory authority. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual inspections according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(3) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose

connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results according to according to section C.6(a)(1)(vi) for centrifugal compressors, or H.5(a)(2)(i) for pneumatic pumps, as applicable.

(c) For each cover, you must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

(2) You must initially conduct the inspections specified in paragraph (c)(1) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e)(11) and (12) of this section. For centrifugal compressors, you must maintain records of the inspection results according to section C.6(a)(1)(iv). For reciprocating compressors, you must maintain records of the inspection results according to C.6(a)(2)(iv)(D).

(d) For each bypass device, except as provided for in section D.1(b)(3)(ii), you must meet the requirements of paragraphs (d)(1) or (2) of this section.

(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere.

(2) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(e) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover as specified in paragraphs (a), (b), or (c) of this section, you must meet the requirements of paragraphs (e)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21, 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21, 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in EPA Method 21, 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (e)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in EPA Method 21, 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (e)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (e)(6)(ii) of this section, the detection instrument must meet the performance criteria of EPA Method 21, 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 8.1.1 of EPA Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream.

For process streams that contain nitrogen, air, or other inerts that are not volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (e)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (e)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (e)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (e)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (e)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (e)(9)(i) and (ii) of this section, except as provided in paragraph (e)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a), (b), or (c) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (e)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in sections that reference this section.

E VOC Emission Control Device Requirements

[These requirements do not apply to control devices used on storage vessels.]

E.1 Initial Control Device Compliance Requirements

You must meet the applicable requirements of this section for each control device used to comply with VOC emission reduction requirements.

(a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and the continuous compliance requirements in section F(e).

(1) Each combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b), with the exceptions noted in section F(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b), with the exceptions noted in section F(a).

(iii) You must operate at a minimum temperature of 760° Celsius for a control device, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of section F(c).

(3) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using EPA Method 22 of 40 CFR part 60, appendix A-7, to determine visible emissions.

(b) You must operate each control device installed to control VOC emissions from your emissions source in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from your VOC emissions source through the closed vent system to the control device. You may vent more than one source to a control device used to comply with this rule.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (g), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2) for centrifugal compressors, as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Following the compliance date established by your regulatory authority for the source using the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (a)(2) of this

section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement.

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

E.2 Continuous Control Device Monitoring Requirements

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet VOC emission control requirements.

(a) For each control device used to comply with the VOC emission reduction requirements, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with section E.1(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel, or used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the

continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in 40 CFR 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in 40 CFR 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under section F(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater.

(vii) For a non-regenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in section F(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under section F(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of F(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A).

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of section E.1(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of section F(b) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of section F(c) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under section F(d) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of section F(b) to demonstrate that the condenser achieves the applicable performance requirements in section E.1(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of section F(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in section E.1(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you meet section E.1(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in section C.5(a)(2)(viii)(D) is less than 95.0 percent.

(3) If you meet section E.1(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in section C.5(a)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to section D.1(b)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to section D.1(b)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under section F(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under section F(d).

(ii) Failure of the monthly visible emissions test conducted under section F(e)(3) occurs.

F Performance Test Procedures

This section applies to the performance testing of control devices used to demonstrate compliance with your VOC emission control requirements. You must demonstrate that a control device achieves the performance requirements specified for your centrifugal compressor using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer, as relevant and allowed for compliance demonstration purposes.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) *A flare that is designed and operated in accordance with 40 CFR 60.18(b).* You must conduct the compliance determination using EPA Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with 40 CFR 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of section E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of section E.1(a) or A.2(e)(1). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use EPA Method 1 or 1A, 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in EPA Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using EPA Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in section E.1(a)(1)(i) or (a)(2), or section A.2(e)(1)(i)(D)(*1*) or (e)(1)(ii), you must

use EPA Method 25A at 40 CFR part 60, appendix A-7. You must use EPA Method 4 at 40 CFR part 60, appendix A-3 to convert the EPA Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20°Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by EPA Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

$E_{i,}$ = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use EPA Method 25A, 40 CFR part 60, appendix A-7 to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in section E.1(a)(1)(ii) or section A.2(e)(1)(i)(D)(*2*). You may also use EPA Method 18, 40 CFR part 60, appendix A-6 to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the EPA Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use EPA Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the EPA Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the EPA Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of EPA Method 3A or 3B, 40 CFR 60, appendix A-2, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after the compliance date for your source as established by your regulatory authority.

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressors, if you do not continuously monitor the gas flow rate in accordance with section E.2(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in section E.1(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressors, you must establish a limit on temperature in accordance with section E.2(f) and continuously monitor the temperature as required by section E.2(d).

(c) *Control device design analysis to meet the requirements of section E.1(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon

used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the regulatory authority do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The regulatory authority may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with EPA Method 2A, 40 CFR part 60, appendix A-1 (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using EPA Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using EPA Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and EPA Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by EPA Method 4, 40 CFR part 60, appendix A-3 following the procedure specified in paragraphs (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in EPA Method 3C, 40 CFR part 60, appendix A-2, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using EPA Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the EPA Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the integrated bag sample required by EPA Method 3C, 40 CFR part 60, appendix A-2, sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A-2, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only).

(8) Carbon monoxide must be determined using EPA Method 10, 40 CFR part 60, appendix A-4. Run the test simultaneously with EPA Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using EPA Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three EPA Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—“EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards”.

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by EPA Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using EPA Method 22, 40 CFR part 60, appendix A-7. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date

and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from EPA Method 22, 40 CFR part 60, appendix A-7, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average EPA Method 25A, 40 CFR part 60, appendix A-7, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC required under this rule.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report. Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including

information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Officer; OAQPS CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to Oil_and_Gas_PT@EPA.GOV.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section and maintaining the records specified in A.5(a)(6) or E.2(a)(1)(ii).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

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G Equipment VOC Leaks at Natural Gas Processing Plants

G.1 Applicability

(a) The group of all equipment, except compressors and sampling connection systems, within a process unit located at an onshore natural gas processing plant.

(b) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by the requirements of section G.2 if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the requirements of section G.2.

(c) The equipment within a process unit subject to VOC emission control requirements located at onshore natural gas processing plants is exempt from this section if they are subject to and controlled according to subparts VVa or GGGa of 40 CFR part 60.

G.2 What VOC Emission Requirements Apply to Equipment at a Natural Gas Processing Plant?

(a) You must comply with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3.

(b) You may elect to comply with the requirements of sections G.6.1 and G.6.2, as an alternative.

(c) You must comply with the provisions of sections G.7 and G.8 of this section, except as provided in section G.3.

G.3 What Exceptions Apply to the Equipment Leak VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

(a) You may comply with the following exceptions to the provisions of section G.2.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in section G.7(b) except as provided in paragraph (b)(4) of this section, and section G.5.2 of this rule.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in section G.5.7.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a non-fractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and section G.5.2(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a non-fractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(e) An owner or operator may use the following provisions instead of section G.7(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM Method D86-96.

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96.

G.4 How Do I Demonstrate Initial and Continued Compliance with the VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

For equipment subject to VOC emission control requirements at natural gas processing plants, initial and continuous compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3; G.6, as an alternative; and G.7 and G.8, except as provided in section G.3

G.5 What VOC Emission Control Requirements Apply to Equipment at Natural Gas Processing Plants

G.5.1 VOC Emission Control Requirements: General

(a) Each owner or operator subject to the provisions of this rule shall demonstrate compliance with the requirements of sections G.5.2 through G.5.8 for all equipment within 180 days and for G.5.9 within 12 months of the compliance date established by your regulatory authority.

(b) Compliance with sections G.5.2 to G.5.9 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in G.7.

G.5.2 What Equipment VOC Emission Control Requirements Apply to Pressure Relief Devices in Gas/Vapor Service?

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in section G.7(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in section G.5.7.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in section G.7(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in section G.5.8 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in section G.5.7.

G.5.3 What Equipment VOC Emission Control Requirements Apply to Pumps in Light Liquid Service?

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in G.7(b), except as provided in paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in G.7(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of G.5.8; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in G.7(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in G.7(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of G.5.8, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in G.8(a)(6)(i), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

G.5.4 What Equipment VOC Emission Control Requirements Apply to Open-Ended Valves or Lines?

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a) through (c) of this section.

(e) Open-ended valves or lines containing materials which would auto-catalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

G.5.5 What Equipment VOC Emission Control Requirements Apply to Valves in Gas/Vapor Service and in Light Liquid Service?

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in G.7(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii),

except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with section G.6.1 or section G.6.2, count the new valve as leaking when calculating the percentage of valves leaking as described in section G.6.2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in section G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in section G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in section G.7(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the permitting authority.

(g) Any valve that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in section G.8(a)(6)(ii), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

G.5.6 What Equipment VOC Emission Control Requirements Apply to Pumps, Valves, and Connectors in Heavy Liquid Service and Pressure Relief Devices in Light Liquid or Heavy Liquid Service?

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in section G.7(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in section G.5.7.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under sections G.5.3(c)(2) and G.5.5(e).

G.5.7 What Delay of Repair of Equipment Requirements Apply When Equipment Component Leaks Have Been Detected?

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with section G.5.8.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

G.5.8 What VOC Emission Control Requirements Apply for Closed Vent Systems and Control Devices?

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this rule shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95.0 percent or greater.

(c) Each enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) shall be designed to reduce the mass content of VOC emissions by 95.0 percent or greater in accordance with the requirements of section F(b).

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this rule shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual inspections according to the procedures in section G.7(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in section G.8(a)(3).

(4) For each inspection conducted in accordance with section G.7(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this rule shall be operated at all times when emissions may be vented to them.

G.5.9 What VOC Emission Control Requirements Apply to Connectors in Gas/Vapor Service and in Light Liquid Service?

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks within12 months of the compliance date. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in section G.5.7 or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in section G.7(b) and, as applicable, section G.7(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$$\%C_L = C_L / C_t * 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in G.7(b).

C_t = Total number of monitored connectors in the process unit.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in section G.5.7. A first attempt at repair as defined in this rule shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors.* (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from recordkeeping and reporting requirements. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this rule. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this rule are identified as a group, and the number of connectors subject to the requirements is indicated.

G.6 Alternative Standards

G.6.1 Alternative Standards for Valves—Allowable Percentage of Valves Leaking

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the permitting authority that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in section G.8(b)(4).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the permitting authority.

(3) If a valve leak is detected, it shall be repaired in accordance with section G.5.5(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements shall be monitored within one week by the methods specified in section G.7(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements.

(d) Owners and operators who elect to comply with this alternative standard shall not have a natural gas processing plant subject to the equipment component VOC emission control requirements with a leak percentage greater than 2.0 percent, determined as described in section G.7(h).

G.6.2 Alternative Standards for Valves—Skip Period Leak Detection and Repair

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the permitting authority before implementing one of the alternative work practices.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in section G.5.5.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in section G.5.5 but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in section G.7(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for a process unit following one of the alternative standards in this section must be monitored in accordance with section G.5.5(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

G.7 Equipment Leak Test Methods and Procedures

(a) In conducting the performance tests, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section.

(b) The owner or operator shall determine compliance with the standards in sections G.5.2 through G.5.9, and as follows:

(1) EPA Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in EPA Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in EPA Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in section G.8(a)(5)(v). Divide these readings by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in sections G.5.2, G.5.3(e), G.5.5(f), and G.5.8(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) EPA Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 must be used.

(2) Organic compounds that are considered by the permitting authority to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the permitting authority disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) EPA Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device[160] shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m4/(MJ-sec) (metric units) = 0.087 ft^4/(Btu-sec) (English units).

[160] The equivalent device must be reviewed and approved by EPA through the SIP review process.

(4) The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component "i," ppm

H_i = net heat of combustion of sample component "i" at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

(5) EPA Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) EPA Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with section G.6.1 or section G.6.2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with section G.5.5(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

G.8 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*. Each owner or operator subject to the VOC equipment leak requirements specified in section G shall maintain the records specified in paragraphs (a)(1) through (10), as applicable, onsite or at the nearest local field office for at least five years.

(1) An owner or operator of more than one facility subject to the requirements of section G may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(2) The owner or operator shall record the information specified in paragraphs (a)(2)(i) through (v) of this section for each monitoring event required by sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(3) When each leak is detected as specified in sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) Maximum instrument reading measured by EPA Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be non-repairable, except when a pump is repaired by eliminating indications of liquids dripping.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(4) The following information pertaining to the design requirements for closed vent systems and control devices described in section G.5.8 shall be recorded and kept in a readily accessible location:

(i) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(iii) A description of the parameter or parameters monitored, as required in section G.5.8(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(iv) Periods when the closed vent systems and control devices required in sections G.5.2 and G.5.3 are not operated as designed, including periods when a flare pilot light does not have a flame.

(v) Dates of startups and shutdowns of the closed vent systems and control devices required in sections G.5.2 and G.5.3.

(5) The following information pertaining to all equipment subject to the requirements in sections G.5.1 to G.5.9 shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for equipment subject to the requirements of this rule.

(ii)(A) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of sections G.5.3(e) and G.5.5(f).

(B) The designation of equipment as subject to the requirements of sections G.5.3(e) or section G.5.5(f) shall be signed by the owner or operator. Alternatively, owner or operator may establish a mechanism[161] with their permitting authority that satisfies this requirement.

(C) A list of equipment identification numbers for pressure relief devices required to comply with section G.5.2.

(iii)(A) The dates of each compliance test as required in sections G.5.2, G.5.3(e), and G.5.5(f).

(B) The background level measured during each compliance test.

(C) The maximum instrument reading measured at the equipment during each compliance test.

(iv) A list of identification numbers for equipment in vacuum service.

(v) Records of the information specified in paragraphs (a)(5)(v)(A) through (F) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of EPA Method 21 of appendix A-7 of this part and section G.7(b).

(A) Date of calibration and initials of operator performing the calibration.

(B) Calibration gas cylinder identification, certification date, and certified concentration.

(C) Instrument scale(s) used.

(D) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of EPA Method 21 of appendix A-7 of this part.

[161] The mechanism must be reviewed and approved by EPA through the SIP review process.

(E) Results of each calibration drift assessment required by section G.7(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(F) If an owner or operator makes their own calibration gas, a description of the procedure used.

(vi) The connector monitoring schedule for each process unit as specified in section G.5.9(b)(3)(v).

(vii) Records of each release from a pressure relief device subject to section G.5.2.

(6) The following information pertaining to all valves subject to the requirements of section G.5.5(g) and (h), all pumps subject to the requirements of section G.5.3(g), and all connectors subject to the requirements of section G.5.9(e) shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(ii) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(7) The following information shall be recorded for valves complying with section G.6.2:

(i) A schedule of monitoring.

(ii) The percent of valves found leaking during each monitoring period.

(8) The following information shall be recorded in a log that is kept in a readily accessible location:

(i) Design criterion required in section G.5.3(d)(5) and explanation of the design criterion; and

(ii) Any changes to this criterion and the reasons for the changes.

(A) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions:

(*1*) An analysis demonstrating the design capacity of the natural gas processing plant,

(*2*) A statement listing the feed or raw materials and products from the processing plant(s) and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(*3*) An analysis demonstrating that equipment is not in VOC service.

(9) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(10) The following recordkeeping requirements apply to pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor service and light liquid service, pumps, valves and connectors in light heavy liquid service and pressure relief devices in light liquid or heavy liquid service, connectors in gas/vapor service and in light liquid service, and alternative standards for valves.

(i) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(ii) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(A) The instrument and operator identification numbers and the equipment identification number.

(B) The date the leak was detected and the dates of each attempt to repair the leak.

(C) Repair methods applied in each attempt to repair the leak.

(D) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(E) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(F) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(G) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(H) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(I) The date of successful repair of the leak.

(J) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of section G.5. The designation of equipment that has no detectable emissions that is subject to the provisions of section G.5 must be signed by the owner or operator.

(b) *Reporting requirements*. Each owner or operator subject to the VOC equipment leak requirements shall comply with the reporting requirements of paragraphs (b)(1) through (5).

(1) Each owner or operator subject to the equipment leak VOC emission control requirements of section G.5 shall submit semiannual reports to the permitting authority beginning 6 months after a facility becomes subject to VOC emission control requirements of section G.5.8.

(2) The initial semiannual report to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) Number of valves subject to the requirements of section G.5.5, excluding those valves designated for no detectable emissions under the provisions of section G.5.5(f).

(iii) Number of pumps subject to the requirements of section G.5.3, excluding those pumps designated for no detectable emissions under the provisions of section G.5.3(e) and those pumps complying with section G.5.3(f).

(iv) Number of connectors subject to the requirements of section G.5.9.

(v) Number of pressure relief devices subject to the requirements, except for those pressure relief devices designated for no detectable emissions under the provisions of section G.5.2 (a) and those pressure relief devices complying with section G.5.2 (c).

(3) All semiannual reports to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) For each month during the semiannual reporting period,

(A) Number of valves for which leaks were detected as described in section G.5.5(b) or section G.6.2,

(B) Number of valves for which leaks were not repaired as required in section G.5.5(d)(1),

(C) Number of pumps for which leaks were detected as described in section G.5.3(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(D) Number of pumps for which leaks were not repaired as required in section G.5.3(c)(1) and (d)(6),

(E) Number of compressors for which leaks were detected as described in section G.5.3(f),

(F) Number of connectors for which leaks were detected as described in section G.5.9(b)

(G) Number of connectors for which leaks were not repaired as required in section G.5.9(d), and

(H) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(iii) An owner or operator must include the following information in all semiannual reports:

(A) Number of pressure relief devices for which leaks were detected; and

(B) Number of pressure relief devices for which leaks were not repaired.

(iv) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(v) Revisions to items reported according to paragraph (b)(1) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(4) An owner or operator electing to comply with the provisions of section G.6.1 or section G.6.2 shall notify the permitting authority of the alternative standard selected 90 days before implementing either of the provisions.

(5) An owner or operator shall report the results of all performance tests to the permitting authority.

G.9 Definitions

As used in this model rule, all terms not defined in section G for equipment leaks at natural gas processing plants shall have the meaning given them in subpart VVa of part 60 and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

Equipment, as used in the standards and requirements in this rule relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this rule.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in sections G.7(e) and G.3(e)(2).

In wet gas service means that a piece of equipment (except compressors and sampling connection systems) contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Non-fractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Underground storage vessel means a storage vessel stored below ground.

H Pneumatic Pumps: VOC Emissions Control Requirements

H.1 Applicability

Each pneumatic pump, which is a natural gas-driven diaphragm pump located at:

(a) A natural gas processing plant; or

(b) A well site. A natural gas-driven diaphragm pump at a well site that is in operation less than 90 days per calendar year is not a source subject to VOC requirements under this rule provided that the owner/operator keeps records of the days of operation each calendar year and submits such records to the regulatory authority upon request. For the purposes of this rule, any period of operation during a calendar day counts toward the 90 calendar day threshold.

For purposes of the requirements specified in this section, we refer to these pumps as natural gas-driven pneumatic pumps.

H.2 What VOC Emission Reduction Requirements Apply to Natural Gas-Driven Pneumatic Pumps?

For each natural gas-driven pneumatic pump, you must comply with the VOC emission control requirements, based on VOC, in either paragraph (a) or (b)(1) of this section, as applicable.

(a) Each natural gas-driven pneumatic pump at a natural gas processing plant must have a VOC emission rate of zero.

(b)(1) For each natural gas-driven pneumatic pump at a well site, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(2), (3) and (4) of this section.

(2) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b)(1) of this section. If you do not

have a control device installed on site by the compliance date established by your regulatory authority and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with section H.5(b)(1)(i) in your next annual report, certifying that there is no available control device or process on site and maintain the records in section H.5(a)(1)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to submit the certification in section H.2(b)(2)(i) and must submit the information in section H.5(b)(2) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2). You must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(3) If the control device available on site is unable to achieve a 95.0 percent reduction and there is no ability to route the emissions to a process, you must still route the natural gas-driven pneumatic pump's emissions to that existing control device. If you route the pneumatic pump to a control device installed on site that is designed to achieve less than a 95.0 percent reduction, you must submit the information specified in section H.5(b)(1)(iii) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2).

(4) If you determine, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraph (b)(4)(i) through (iv) of this section must be met.

(i) You must conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(4)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(4)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of section H.2(b)(4)(iii) of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device on site or to a process must include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. You must prepare the assessment of technical infeasibility under the direction or supervision of the qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) You must maintain the records specified in section H.5(a)(1)(iv).

(5) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b)(1) of this section, and instead must comply with paragraph (b)(2) of this section and report the change in your next annual report in accordance with section H.5(b)(2)(iii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the natural gas-driven pneumatic pump subject to VOC emission control requirements through a closed vent system that meets the requirements of section D.1(b).

(d) You must demonstrate initial compliance with standards that apply to natural gas-driven pneumatic pumps subject to VOC emission requirements as required by section H.3.

(e) You must demonstrate continuous compliance with standards that apply to natural gas-driven pneumatic pump sources subject to VOC emission requirements as required by section H.4.

(f) You must perform the reporting as required by section H.5(b) and the recordkeeping as required by H.5(a).

H.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission control requirements for natural gas-driven pneumatic pumps specified in paragraphs (a) through (h) of this section, as applicable.

(a) If you own or operate a pneumatic pump located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero VOC emissions.

(b) If you own or operate a natural gas-driven pneumatic pump located at a well site, you must reduce emissions in accordance with section H.2(b)(1), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(c) If you own or operate a natural gas-driven pneumatic pump located at a well site and there is no control device or process available on site, you must submit the certification in section H.5(b)(1)(i).

(d) If you own or operate a natural gas-driven pneumatic pump located at a well site, and you are unable to route to an existing control device due to technical infeasibility, and you are unable to route to a process, you must submit the certification in section H.5(b)(1)(ii).

(e) If you own or operate a natural gas-driven pneumatic pump located at a well site and you reduce emissions in accordance with section H.2(b)(3), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(f) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the initial closed vent system inspection required in section D.2 by the date established by your regulatory authority.

(g) You must include a listing of the natural gas-driven pneumatic pumps subject to VOC emission requirements specified in paragraphs (a) through (e) of this section in the initial annual report submitted for your natural gas-driven pneumatic pump according to the requirements of section H.5(b).

(h) You must maintain the records as specified in section H.5(a) for each natural gas-driven pneumatic pump subject to the VOC emission control requirements of section H.

H.4 Continuous Compliance Demonstration Requirements

For each natural gas-driven pneumatic pump you must demonstrate continuous compliance according to paragraphs (a) and (b) of this section.

(a) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the periodic closed vent system inspections required in section D.2, as applicable.

(b) You must submit the annual reports required by section H.5(b) and maintain the records as specified in section H.5(a).

H.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*.

(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (v) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the rule (as established by the regulatory authority), location and manufacturer specifications for each natural gas-driven pneumatic pump.

(ii) Records of deviations in cases where the natural gas-driven pneumatic pump was not operated in compliance with the requirements specified in section H.2.

(iii) Records on the control device used for control of emissions from a natural gas-driven pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than a 95.0 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to H.2(b)(4) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process, including the qualified professional engineer certification according to H.2(b)(4)(ii) and the records of the engineering assessment of technical infeasibility performed according to H.2.(b)(4)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the regulatory authority.

(2) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must maintain the records identified in paragraphs (a)(2)(i) through (iv) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of each closed vent system inspection required under section D.2(a) and (b).

(ii) If you are subject to the bypass requirements of section D.1(b)(3), a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(iii) If you are subject to the closed vent system no detectable emissions requirements of section D.2(e), records of the monitoring conducted in accordance with section D.2(e).

(iv) For each closed vent system routing to a control device or process, the records of the assessment conducted according to section D.1(b)(4):

(A) A copy of the assessment conducted according to section D.1(b)(4);

(B) A copy of the certification according to section D.1(b)(4)(i); and

(C) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the regulatory authority.

(b) *Reporting Requirements*.

For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1) through (4) of this section.

(1) In the initial annual report, a certification that the natural gas-driven pneumatic pump meets one of the conditions described in paragraphs (b)(1)(i), (ii) or (iii) of this section.

(i) No control device or process is available on site.

(ii) A control device or process is available on site and the owner or operator has determined in accordance with H.2(b)(4) that it is technically infeasible to capture and route the emissions to the control device or process.

(iii) Emissions from the natural gas-driven pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95.0 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(2) For any natural gas-driven pneumatic pump which has been previously reported as required under paragraph (b)(1) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the natural gas-driven pneumatic pump and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(2)(i), (ii) or (iii) or (iv) of this section.

(i) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(iii) of this section.

(ii) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(ii) of this section.

(iii) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump now report according to paragraph (b)(1)(i) of this section.

(iv) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with H.2(b)(4) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(3) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(4) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, the records specified in paragraphs (a)(2)(i), (ii), (iii) and (iv)(B) of this section.

H.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Routed to a process or *route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

I Fugitive Emissions Components VOC Emissions Control Requirements

I.1 Applicability

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day. The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads. Whether a separate tank battery surface site is subject to this rule has no effect on the status of a well site that only contains wellheads.

(b) The collection of fugitive emission components at a gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline.

I.2 What VOC Emission Control Requirements Apply to the Collection of Fugitive Emission Components at a Well Site and a Gathering and Boosting Station?

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site and gathering and boosting station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (f) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and cover requirements in section D. The collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf of gas per barrel of oil produced are subject only to the requirements in paragraph (g) of this section.

(a) You must monitor all fugitive emission components, as defined in section I.6, in accordance with paragraphs (b) through (e) of this section and section I.2(a) and I.3(a). You must repair all sources of fugitive emissions in accordance with paragraph (f) of this section. You must keep records in accordance with section I.5(a) and report in accordance with section I.5(b). For purposes of this section, fugitive emissions are defined as: any visible emission from a fugitive emission component using optical gas imaging or an instrument reading of 500 ppm or greater using EPA Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, at a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.

(2) Technique for determining fugitive emissions (*i.e.*, EPA Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

(3) Manufacturer and model number of fugitive emission detection equipment to be used.

(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (f) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of $\leq$60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.*, steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using EPA Method 21 at 40 CFR part 60, appendix A-7, your plan must also include the elements specified in paragraphs (c)(8)(i) and (ii) of this section. For the purposes of complying with the fugitive emissions monitoring program using EPA Method 21, a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of EPA Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.*, 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of EPA Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(4) of this section, at a minimum, as applicable.

(1) Sitemap.

(2) If you are using OGI, a defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using EPA Method 21, your plan must also include a list of fugitive emissions components to be monitored and the method for determining location of fugitive

emissions components to be monitored in the field (*e.g.*, tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with section I.4(a)(3), and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with section I.4(a)(4).

(e) Each monitoring survey shall observe each fugitive emissions component, as defined section I.6, for fugitive emissions.

(f) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (f)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of sections A.4(d)(4) through (7) and D.2(e)(9) through (12), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a gathering and boosting station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next gathering and boosting station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than 30 days after being repaired or replaced, to ensure that there are no fugitive emissions.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using EPA Method 21 or optical gas imaging within 30 days of being repaired.

(ii) For each repair or replacement that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use EPA Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the EPA Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of EPA Method 21 are used.

(B) Operators must use the EPA Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of EPA Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(g) For each well with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (g)(2) of this section.

(1) You must determine the gas to oil ratio of your well using generally accepted methods.

(2) You must maintain the records specified in section I.5 (a)(4)

I.3 Initial Compliance Demonstration

To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must comply with paragraphs (a) through (e) or (f), if applicable, of this section.

(a) You must develop a fugitive emissions monitoring plan as required in sections I.2(b), (c), and (d).

(b) You must conduct an initial monitoring survey as required in paragraphs (b)(1) and (2), as applicable

(1) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of becoming subject to VOC emission control requirements of section I.

(2) Each gathering and boosting station with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of being subject to VOC emission control requirements of section I.

(c) You must maintain the records specified in section I.5(a).

(d) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(e) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(f) You must determine the gas to oil ratio of your well using generally accepted methods and maintain the records specified in section I.5(a)(4).

I.4 Continuous Compliance Demonstration

For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must demonstrate continuous compliance with the fugitive emission standards specified in section I.2 according to paragraphs (a) through (d) or (e), if applicable, of this section.

(a) You must conduct periodic monitoring surveys of each collection of fugitive emissions components at a well site and a gathering and boosting station subject to VOC emission control requirements under section I at the frequencies specified in paragraphs (a)(1) and (a)(2) of this section, with the exceptions noted in paragraphs (a)(3) through (a)(5) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart.

(2) A monitoring survey of the collection of fugitive emissions components at a gathering and boosting station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (a)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (a)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (a)(2) of this section are waived for any collection of fugitive emissions components at a gathering and boosting station located within an area that has an average calendar month temperature below 0°Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The

requirements of paragraph (a)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(b) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(c) You must maintain the records specified in section I.5(a).

(d) You must submit annual reports for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(e) You must recalculate the gas to oil ratio of your well using generally accepted methods annually and maintain the records as required in section I.5(a)(4).

I.5 Recordkeeping and Reporting Requirements

(a) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, the records identified in paragraphs (a)(1) through (3), and (a)(4), if applicable of this section shall be maintained onsite or at the nearest local field office for at least five years.

(1) The fugitive emissions monitoring plan as required in I.2(b), (c), and (d).

(2) The records of each monitoring survey as specified in paragraphs (a)(2)(i) through (ix) of this section.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. You must note the training and experience of the operator.

(iv) Monitoring instrument used.

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a gathering and boosting station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

(vi) Fugitive emissions component identification when EPA Method 21 is used to perform the monitoring survey.

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(viii) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(ix) Documentation of each fugitive emission, including the information specified in paragraphs (a)(2)(ix)(A) through (L) of this section.

(A) Location.

(B) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(C) Number and type of components for which fugitive emissions were detected.

(D) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(E) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 is used for monitoring.

(F) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(G) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii).

(H) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (a)(2)(v) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(I) Repair methods applied in each attempt to repair the fugitive emissions components.

(J) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(K) The date of successful repair of the fugitive emissions component.

(L) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(3) For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

(4) For the collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf per stock barrel of oil produced, you must maintain:

(A) A record of the gas to oil ratio analyses documenting a gas to oil ratio of less than 300 scf per stock barrel of oil produced, conducted pursuant to sections I.3(f) and I.4(e).

(B) The location of the well and the United States Well ID Number.

(C) A record of the determination signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

(b) Annual reports shall be submitted for the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each gathering and boosting station within the company-defined area, that are subject to VOC emission control requirements under section I. Each annual report shall include the records of each monitoring survey including the information specified in paragraphs (b)(1) through (12) of this section. For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a gathering and boosting station subject to VOC emission control requirements under section I may be included in a single annual report.

(1) Date of the survey.

(2) Beginning and end time of the survey.

(3) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(5) Monitoring instrument used.

(6) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(7) Number and type of components for which fugitive emissions were detected.

(8) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(9) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(10) The date of successful repair of the fugitive emissions component.

(11) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(12) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

I.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Gathering and boosting station means any permanent combination of one or more compressors that collects natural gas from well sites and moves the natural gas at increased pressure into gathering pipelines to the natural gas processing plant or into the pipeline. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a gathering and boosting station for purposes of this section.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to section A.2(c) or (d) or section D, thief hatches or other openings on a controlled storage vessel not subject to section A, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at section I.1, *well site* also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.*, centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

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PROCEDURES FOR IDENTIFYING REASONABLY AVAILABLE CONTROL TECHNOLOGY FOR STATIONARY SOURCES OF PM-10

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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ABSTRACT

This guidance document sets forth procedures and identifies sources of information that will assist state and local air pollution control agencies in determining RACT for PM-10 emissions from existing stationary sources on a case-by-case basis. It provides an annotated bibliography of documents to aid in identifying the activities that cause PM-10 emissions as well as applicable air pollution control measures and their effectiveness in reducing emissions for the industries and processes listed on Table 1-1. The most stringent state total particulate matter (PM) emission limits are identified for the stationary sources shown on Table 1-1 and compared to available emission test data. Finally, guidance is provided on procedures for estimating total capital investment and total annual cost of the control measures which are generally used to control PM-10 emissions.

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ABBREVIATIONS

acfm	actual cubic feet per minute
AL	Alabama
AK	Alaska
AR	Arkansas
AOD	argon oxygen decarburization
AP-42	EPA publication entitled Compilation of Air Pollutant Emission Factors, Volume I
AZ	Arizona
BACT	Best Available Control Technology
BNA	Bureau of National Affairs
BOPF	Basic Oxygen Process Furnace
BOF	basic oxygen furnace
Btu/hr	British thermal unit per hour
CA	California
CRC	Capital Recovery Cost
CRF	Capital Recovery Factor
CO	Colorado
CT	Connecticut
days/yr	days per year
DE	Delaware
DC	District of Columbia
DC	Direct Cost
EAF	Electric arc furnaces
EPA	United States Environmental Protection Agency
ESP	Electrostatic precipitator
°F	degrees Fahrenheit
FCCU	fluidized catalytic cracking unit
FL	Florida
g/day	grams per day
g/hr	grams per hour
g/kg	grams per kilogram
g/m^3	grams per cubic meter
g/MJ	grams per megajoule
gr/acf	grams per actual cubic feet
gr/dscf	grains per dry standard cubic feet
gr lead/ dscf	grains of lead per dry standard cubic feet
gr/scf	grains per standard cubic feet
GA	Georgia
GJ/hr	Gigajoule per hour
hr/day	hours per day
hr/year	hours per year
HI	Hawaii
IA	Iowa
IC	Indirect annual cost
ID	Idaho

IL	Illinois
IN	Indiana
J/hr	Joules per hour
kg/hr	kilograms per hour
kg/kg	kilogram per kilogram
kg/1000m^2	kilograms per thousand meters squared
kg/Mg	kilograms per megagrams
kPa	kilopascals
kWh	kilowatt-hour
K	degrees Kelvin
KS	Kansas
KY	Kentucky
LA	Louisiana
LAER	Lowest achievable emission rate
lb/barrel	pounds per barrel
lb/1000ft^2	pounds per thousand feet squared
lb/hr	pounds per hour
lb/lb	pound per pound
lb/MMBtu	pounds per million Btu
lb/ton	pounds per ton
m^3	cubic meters
m^3/min	cubic meters per minute
m^3/hr	cubic meters per hour
MA	Massachusetts
MD	Maryland
ME	Maine
mg/scm	milligrams per standard cubic meter
mg/dscm	milligrams per dry standard cubic meter
MI	Michigan
min/hr	minutes per hour
mm H_2O	millimeters of water
Mg	megagrams
Mg/day	megagrams per day
Mg/hr	megagrams per hour
Mg/yr	megagrams per year
mg lead/ kg lead feed	milligrams of lead per kilograms of lead feed
mg lead/ scm	milagrams of lead per standard cubic meter
MN	Minnesota
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
MO	Missouri
MS	Mississippi
MT	Montana
ng/J	nanograms per Joule
NC	North Carolina
ND	North Dakota
NE	Nebraska
NH	New Hampshire

NJ	New Jersey
NM	New Mexico
NSPS	New Source Performance Standards
NTIS	National Technical Information Service
NV	Nevada
NY	New York
OAQPS	Office of Air Quality Planning and Standards (EPA)
OH	Ohio
OK	Oklahoma
PA	Pennsylvania
PM	Particulate matter
PM-10	Particulate matter that is less than or equal to 10 μm
RACT	Reasonably Available Control Technology
RACM	Reasonably Available Control Measures
RI	Rhode Island
SIPs	State Implementation Plans
SC	South Carolina
SD	South Dakota
ton/day	tons per day
ton/hr	tons per hour
ton/yr	tons per year
TN	Tennessee
TX	Texas
UK	United Kingdom
UT	Utah
VE	visible emissions
VT	Vermont
VA	Virginia
WA	Washington
WI	Wisconsin
WV	West Virginia
WY	Wyoming

Symbols

%	percent
μm	micrometers
$	dollars
$/hr	dollars per hour
$/kWh	dollars per kilowatt hour
$/Mg	dollars per Megagram
$/MWh	dollars per megawatt hour
$/ton	dollars per ton
H_2O	water
SO_2	sulfur dioxide

SECTION 1

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) is issuing this document to assist states in identifying reasonably available control technology (RACT) for existing stationary sources of particulate matter having a nominal aerometric diameter of 10 microns or less (PM-10). The EPA has historically defined RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.[1]

Section 172(c)(1) of the Clean Air Act (Act) as amended November 15, 1990, requires that State implementation plans (SIPs) for nonattainment areas provide for the implementation of reasonably available control measures (RACM) including emission reductions obtained through the adoption of RACT. Section 189(2)(1)(C) of the Act requires that SIP's for moderate PM-10 nonattainment areas assure that RACM (including RACT) for PM-10 shall be implemented no later than four years after the area is designated nonattainment.

This guidance document sets forth procedures and identifies sources of information that will assist state and local air pollution control agencies in determining RACT for PM-10 emissions from existing stationary sources on a case-by-case basis. It provides an annotated bibliography of documents to aid in identifying the activities that cause PM-10 emissions as well as applicable air pollution control measures and their effectiveness in reducing emissions for the industries and processes listed on Table 1-1. The most stringent state total particulate matter (PM) emission limits are identified for the stationary sources shown on Table 1-1 and compared to available emission test data. Finally guidance is provided on procedures for estimating total capital investment and total annual cost of the control measures which are generally used to control PM-10 emissions.

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[1]See, for example, 44 FR 53762 (September 17, 1979) and footnote 3 of that notice.

TABLE 1-1. SOURCE CATEGORIES COVERED IN THIS DOCUMENT

Source category	Specific processes
Asphalt and asphaltic concrete plants	
Boilers	Utility - greater than 105 GJ/hr (100 MM Btu/hr) Industrial/commercial - greater than 0.5 GJ/hr (0.5 MMBtu/hr) and less than 105 GJ/hr (100 MM Btu/hr) Coal-fired Oil-fired Wood-fired
Brick manufacturing plants	Kiln
Calciners	
Charcoal plants	
Chemical manufacturing plants	Reactors Blenders Mixers
Coal preparation and cleaning plants	
Concrete batch plants	
Cotton seed milling plants	
Foundries	Aluminum Iron Secondary steel (shredders)
Glass manufacturing plants	
Grain milling operations	
Gypsum product manufacturing and processing plants	
Incinerators	Medical waste Agricultural waste Municipal waste

(Continued)

TABLE 1-1. (Continued)

Source category	Specific processes
Iron and steel facilities	Argon oxygen decarburization Electric arc furnaces Sinter plants Coke batteries Slag handling Blast furnaces Basic oxygen furnaces Scarfing Metal reladling
Lime plants	
Lumber mills	Planing Shaving Waste wood combustion
Marine grain terminals	Shipping - loadout Receiving - unloading Other grain handling
Metallic Minerals Processing Plants	Ore concentrators
Nonmetallic mineral processing plants	Conveyors Screens Quarrying Rock crushers Other materials handling
Paint manufacturing plants	
Petroleum refineries	Catalytic cracking units Boilers Heaters
Phosphate fertilizer plants	
Phosphate rock processing plants	
Plywood, particleboard and waferboard plants (including veneer dryers)	
Portland cement plants	
Primary aluminum reduction facilities	Vertical stud Soderberg Horizontal stud Soderberg Prebaked

(Continued)

TABLE 1-1. (Continued)

Source category	Specific processes
Pulp mills	Kraft Sulfite
Secondary aluminum reduction facilities	
Sugar production plants	Sugar beets
Surface mining operations	
Turbines (oil-fired)	

This document is organized as follows:

Section 2 - RACT Determination: Describes procedures for establishing an emission limit that would require the application of RACT.

Section 3 - Process Emissions and Emissions Control Bibliography: Provides an annotated bibliography of information sources that describe the processes listed on Table 1-1 and the magnitude of uncontrolled and controlled emissions and emission control measures from these processes.

Section 4 - Achievable Emission Limits: Identifies the most stringent state PM emission limits for the processes listed on Table 1-1 and presents available mass emissions test data.

Section 5 - Costs of Control: Describes procedures for estimating total capital investment and total annual cost of control measures.

A list of abbreviations and symbols used in this document is provided in the front of this document.

SECTION 2

DETERMINING REASONABLY AVAILABLE CONTROL TECHNOLOGY

INTRODUCTION

The EPA has defined reasonably available control technology (RACT) as:

> The lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.

RACT is not limited to off-the-shelf control alternatives; it has a technology-forcing aspect to it, and it may vary among different facilities in the same source category depending on the feasibility of implementing particular control strategies at each location.

There are two key criteria that must be satisfied in the determination of RACT: (1) technological feasibility and 2) economic feasibility. This section describes guidelines for evaluating the technological and economic feasibility of control options and making a RACT determination. A case study is also presented.

DETERMINING TECHNOLOGICAL FEASIBILITY

The determination of technological feasibility should concentrate on factors specific to the source in question and should not be an evaluation of the feasibility of control measures for the entire source category. The evaluation should be restricted to the particular processes to be controlled by a single technology application.

For determining technological feasibility, the following steps are recommended:

Step 1. Determine the uncontrolled PM-10 and total particulate matter (PM) emission rates for the source and the nature of those emissions (solid or condensible).

Step 2. Identify a range of available PM-10 emission reduction and control options including process changes, facility redesign, and/or add-on air pollution control devices.

Step 3. Review performance data for the available control options.

Step 4. Identify the lowest PM-10 and/or total PM emission limitations achievable with the available control options and rank the options by performance.

Step 5. Identify the current lowest PM emission limitation that is placed on the source category by Federal, State, or local regulation; the regulation imposing that limit; and the method of determining compliance.

Each step will be discussed further in the subsections that follow.

Step 1. -- Determine Uncontrolled Emission Rates

The baseline emission rates should be determined for PM-10 and total PM from the source before process or operating changes are made or equipment is added to reduce emissions. Baseline emission rates can be determined using source test data, information from reports on the source category, such as those cited in Section 3, and/or emission factors derived from EPA's Compilation of Air Pollution Emission Factors (Office of Air Quality, Planning and Standards (OAQPS), 1985). Baseline emission rates should be calculated for the source operating at its maximum design capacity.

Step 2. -- Identify Available Control Options

In determining the technological feasibility of applying an emission reduction method to a particular source, consider the sources' process and operating procedures, raw materials, the physical plant layout, and any other environmental impacts that will result from controlling PM-10 emissions (i.e., water pollution, waste disposal, and energy requirements). Process changes or changes in raw materials should be investigated for their feasibility for reducing or eliminating emissions or simplifying the selection of an add-on control. Modifying processes or applying control equipment is also influenced by the physical layout of the particular plant. The space available in which to implement such changes may limit the choices and will also affect the costs of control.

Reducing air emissions may adversely affect other resources by increasing pollution of bodies of water, creating additional solid waste disposal problems, or substantially increasing energy demands. A PM-10 control technology may not be feasible if the resulting environmental impacts cannot be mitigated. In many instances, however, PM-10 control technologies have known energy penalties and adverse effects on other media, but such effects and the cost of their mitigation are also known and have been borne by owners of existing sources. Such well-established adverse effects and their costs are normal and assumed to be reasonable and should not, in most cases, justify not using the PM-10 control technology.

In selecting a control device, the size and nature of the particles to be collected must be considered. If the particles are sticky or large and abrasive, a fabric filter may not be suitable. If the emissions contain a significant fraction of particles less than 1 micron in diameter, a device capable of collecting fine particles must be chosen.

Alternative approaches to reducing emissions of particulate matter, including PM-10, are discussed in Control Techniques for Particulate Emissions From Stationary Sources Volumes I and II (EPA, 1982a; EPA, 1982b). The design, operation, and maintenance of general particulate matter control systems, such as mechanical collectors, electrostatic precipitators, fabric filters, and wet scrubbers, are discussed in Volume I. The collection efficiency of each system is discussed as a function of particle size. Information is also presented regarding energy and environmental considerations, and procedures for estimating costs of particulate matter control equipment. Volume II discusses the emission characteristics and control technologies applicable to specific source categories. Secondary environmental impacts are also discussed.

Additional sources of information on control technology are background information documents for new source performance standards, many of which are identified in section 2 of this document, and Identification, Assessment, and Control of Fugitive Particulate Emissions (EPA, 1986). The EPA's Control Technology Center (919/541-0800) and the RACT/BACT/LAER Clearinghouse are other possible sources of information. Information on the RACT/BACT/LAER Clearinghouse can be obtained from the following:

RACT/BACT/LAER Clearinghouse (MD-13)
U.S. Environmental Protection Agency
Emission Standards Division
Research Triangle Park, North Carolina 27711
Phone: (919) 541-2736

Step 3. -- Review Performance Data

Where available, performance data for emission control devices applied to the source categories listed in Table 1-1 is given in section 4. Section 3 provides an annotated bibliography of information sources that describe the processes listed in Table 1-1 and the magnitude of uncontrolled and controlled emissions and emission control measures. As mentioned above, Volume I of Control Techniques for Particulate Emissions From Stationary Sources (EPA, 1982a) contains information on collection efficiency as a function of particle size for control devices. Compilation of Air Pollutant Emission Factors (OAQPS, 1985) provides similar kinds of information.

Manufacturer's brochures are also a source of performance data and, for the numerous proprietary-design control devices, they may be the only source. General literature references such as section 20 in the Chemical Engineers Handbook (Perry, 1984) are an additional source of performance data.

Step 4. -- Identify the Lowest Emission Limitation Achievable

The available control options should be listed in a table designed for easy comparison of the attributes of each option. The lowest PM-10 and total PM emission rates achievable by each option should be listed in consistent units [such as milligrams per dry standard cubic meter (mg/dscm), kilograms per hour (kg/hr), kilograms per megagram of product (kg/Mg) or megagrams per year (Mg/yr).] The control effectiveness or percent reduction of emissions from the baseline levels determined in Step 1 should also be listed in the table for each control option.

The control effectiveness of add-on PM control devices varies with the size distribution of particles in the exhaust gases. Particle size distributions for many processes are included in the individual industry sections or Appendix C.1 of EPA's Compilation of Air Pollut Emission Factions (OAQPS, 1985). When the particle size distribution for a particular process is not available, Appendix C.2 (of OAQPS, 1985) includes guidelines and a worksheet for calculating the particle size distribution and size specific emissions from a control device (i.e., an achievable PM-10 emission rate).

Step 5. -- Identify the Current Lowest Emission Limitation

Emission limitations that currently apply to nearly every source category that emits PM are embodied in Federal and State air pollution control regulations. Several States have also delegated authority to local agencies for implementation of air pollution control programs. Furthermore, there may be consent agreements or permit conditions that place specific emission standards on individual sources. Section 4 presents a discussion of the most stringent State standards and, when applicable, the Federal new source performance standards (NSPS) for selected source categories (see Table 1-1). Section 4 should be used as a starting point in determining the lowest emission limitation currently applicable to sources similar to the one for which RACT is being determined. The individual State and Federal regulations should be reviewed to determine their applicability or appropriateness to the type of source in question and the method of determining compliance.

Since most PM emission limits pertain to total PM as measured by a stack sampling method or visible emission observation method, it will also be necessary to estimate an equivalent PM-10 emission limit. An equivalent PM-10 emission limit can be established by determining the fraction of total PM that is PM-10 and applying the fraction, with a "safety factor" to allow for the variations in emissions, to the total PM emission limit. This procedure incorporates key information that was determined above in Steps 1 through 4, such as uncontrolled emission rates and achievable emission rates. A suggested procedure to calculate an equivalent PM-10 limit is outlined below. An example of the application of the procedure is included with the case study.

a. Determine the percent control that is required to meet the total PM allowable emission limit.

b. Select the most inefficient control technology that could achieve this emission reduction.

c. Determine the total PM emission rate that can be actually achieved by this control technology.

d. Calculate a "safety factor" to account for the difference between the total PM emission limit and the controlled total PM emissions. (Divide the total PM allowable emission limit by the actual achievable total PM emissions).

e. Determine the particle size distribution of the uncontrolled exhaust stream.

f. Determine the PM-10 emission rate that should be achieved by the control technology identified in Step b above.

g. Multiply the achievable PM-10 emission rate by the "safety factor" calculated from Step d. The product is a PM-10 emission limit that would require the same level of control.

DETERMINE ECONOMIC FEASIBILITY

Economic feasibility considers the cost of reducing emissions and the difference in costs between the particular source for which RACT is being determined and other similar sources that have implemented emission reductions. The EPA presumes that it is reasonable for similar sources to bear similar costs for emissions reduction. Economic feasibility rests very little on assertions of the ability of a particular source to "afford" to reduce emissions to the level of similar sources.

The following steps are recommended for evaluating the economic feasibility of the available control options.

Step 1. -- Develop Capital and Annual Costs

The capital costs and annualized costs of an emission reduction technology should be considered in determining its economic feasibility. Procedures for estimating total capital investment and total annual cost of control measures are described in section 5. These procedures are developed in greater detail in the OAQPS Control Cost Manual (OAQPS, 1990). Unless there are reasons not to, these estimating procedures should be followed to assure that all cost estimates are on the same basis and, therefore, can be compared.

The following should be considered when developing the capital and annual costs of a control option:

a. Costs should be determined for technologically efficient control systems. Only auxiliary systems and redundancies necessary to consistently achieve the desired collection efficiency should be included in the costs.

b. The evaluation should specify the control system "battery limits," i.e., the specific area or process segment to be controlled. Inadequate documentation of battery limits is a common reason for confusion in comparisons of costs of the same controls applied to similar sources.

c. Credits and debits associated with the control equipment should be valued consistently and accurately. Credits consist primarily of the value of recovered products. Debits include such items as fuel, labor, equipment, and interest on borrowed capital.

d. The evaluation should include a range of costs for each control option (reflecting the lowest and highest likely cost); the assumptions behind each estimate should be explained.

Step 2. -- Compare Cost Impacts

The primary consideration of the economic impact analysis should be given to comparing the capital and annual costs and the relative cost effectiveness of implementing (e.g., purchasing, installing and operating) the available and technologically feasible control options. The costs of implementing the control options should also be compared with the costs incurred by similar sources that have implemented similarly effective controls measures. The capital and annual costs of each control option should be added to the table created during the analysis of technological feasibility to compare option attributes.

The relative cost effectiveness is another parameter that can be used in comparing control options. Cost effectiveness is calculated as the annual cost of the proposed control option divided by the baseline (i.e., uncontrolled) emissions minus the emission rate of the proposed control, as shown by the following formula:

$$\frac{\text{Control option annual cost}}{(\text{Baseline emissions rate} - \text{Control option emissions rate})}$$

Costs are calculated in dollars per year; emissions rates are calculated in megagrams (tons) per year. The result is a cost-effectiveness number in dollars per megagram (ton) of PM-10 removed. Baseline emissions are essentially uncontrolled emissions calculated using realistic upper boundary operating assumptions.

The cost-effectiveness ratio can be used to compare alternative controls for the same source, and to compare the costs of controlling sources of varying magnitude. However, EPA does not favor making any presumption that control options with cost effectiveness above or below some arbitrary level are reasonable or unreasonable.

Step 3. -- Affordability

The affordability of implementing a control option should generally not be considered in the economic impact analysis because affordability is highly subjective and depends upon the economic viability of a particular source. Consequently, control options should not be eliminated solely on the basis of economic parameters that indicate they are not affordable by the source.

If a company contends that it cannot afford RACT and/or may have to shut-down its operation if RACT controls are imposed, the economic impact analysis will then consist of weighing the benefits (and costs) of the facility remaining open against those of closing. The following items should be considered in the analysis:

a. The extent to which the company will have to absorb the costs of control. (This should be demonstrated with data such as empirical data on supply and demand elasticities, as well as per-unit cost impacts, expected costs to be incurred by competitors, and available industry production capacity.)

b. The company should present data regarding its fixed and variable costs in producing the product affected.

c. If projected revenues exceed the sum of expected variable costs and annual costs of each available control option, closure would not be sufficient justification for concluding that control is economically infeasible.

d. Plant closure costs, including severance pay, relocation costs, demolition costs, and others.

IDENTIFYING RACT

The information gathered in determining the technological and economic feasibility of implementing alternative control options at the source in question can be delineated in a table similar to the example shown as Table 2-1. As a result of comparing the cost, energy and environmental impacts of the control options that achieve the lowest PM-10 emission rates, a reasonably available control technology will be revealed in most cases.

CASE STUDY

The following example is provided for illustration only. The example source is fictitious and has been created to highlight many of the aspects of RACT determination. The cost data and other numbers presented in the example are used only to illustrate the RACT decision making process. Cost data are used in a relative sense to compare costs among control devices. No absolute cost guidelines have been established above which costs are assumed to be too high or below which they are assumed to be reasonable. Determination of appropriate costs is made on a case-by-case basis.

The example source in this section is controlling PM-10 emissions from a boiler using pulverized coal. The purpose of the example is to illustrate points to be considered in developing RACT decision criteria for the source under review.

TABLE 2-1. EXAMPLE SUMMARY TABLE FOR RACT DETERMINATIONS

Parameter/ technology	Fabric filter	ESP	Venturi scrubber	Process change
Uncontrolled emissions, kg/Mg[a]				
a. Total PM				
b. PM-10				
Controlled emissions				
a. Total PM				
b. PM-10				
Control effectiveness, %				
a. Total PM				
b. PM-10				
Current allowable emissions				
a. Total PM, kg/Mg				
b. Opacity, %				
Equivalent PM-10 limit, kg/Mg				
Capital costs, $				
Annual costs, $/yr				
Cost effectiveness, $/Mg				
Energy requirement, kWh/yr				
Wastewater impact				
Solid waste impact				
Other impacts				

[a]Uncontrolled and controlled total PM and PM-10 emission rates and the current allowable rates should be expressed in the same units.

The example is intended to illustrate the process rather than provide universal guidance on what constitutes RACT for this particular source category. RACT must be determined on a case-by-case basis.

Source Description

A control device is required to collect flyash emissions from a coal-fired boiler (dry bottom) burning pulverized bituminous coal. Boiler operating parameters are given in Table 2-2.

Case Study -- Technological Feasibility

Step 1. Determine Uncontrolled Emission Rates --

Based on boiler operating parameters that are summarized on Table 2-2, the uncontrolled total PM and PM-10 emission rates are:

$$\frac{9.153\ g}{m^3} \times \frac{1{,}416\ m^3}{min} \times \frac{60\ min}{hr} \times \frac{kg}{1{,}000\ g}$$

$$= 777.6\ kg/hr \text{ total PM}$$

$$777.6\ kg/hr \times 23/100 = 178.9\ kg/hr \text{ PM-10}$$

If information on inlet PM concentrations were not available, uncontrolled emissions could also be estimated using emission factors in Compilation of Air Pollutant Emission Factors (OAQPS, 1985).

Step 2. Identify Available Control Options --

While many sources may be able to change their processes to reduce or eliminate PM-10 emissions, this is not always possible with a boiler. Changing the fuel from coal to oil or natural gas would reduce PM-10 emissions, but this case study assumes that the location of this boiler makes coal an economical fuel. The collected flyash is a waste product which must be disposed of in a properly permitted landfill. Such arrangements have been made.

Data in Compilation of Air Pollutant Emission Factors (OAQPS, 1985) indicates that emissions from pulverized coal-fired boilers range down to less than 0.6 μm (see size distribution data summarized on Table 2-2). Control Techniques for Particulate Emissions from Stationary Sources - Volume II (EPA,

TABLE 2-2. CASE STUDY:
BOILER OPERATING PARAMETERS

Coal feed rate, Mg/hr (ton/hr)	5.41 (5.97)
Heat input, GJ/hr (MMBtu/hr)	170.7 (162)
Flue gas rate, m^3/min (acfm)	1,416 (50,000)
Flue gas ash loading, g/m^3 (gr/acfm)	9.153 (4.0)
Flue gas temp, K (°F)	436 (325)
Operating hours/year	8,640
Uncontrolled particulate size distribution, % less than stated size (μm):	
15	32
10	23
6	17
2.5	6
1.25	2
1.00	2
0.625	1

[a]From Compilation of Air Pollutant Emission Factors (OAQPS, 1985).

1982b) indicates that electrostatic precipitators (ESPs), fabric filters (baghouses), and wet scrubbers are used to control boiler emissions.

Step 3. Review Performance Data --

Since 23 percent of the emissions from the coal-fired boiler in this case study are less than 10 μm, a control device capable of collecting such fine materials is required. ESPs can be designed to collect flyash particles between 0.1 and 1 μm at 99+ percent efficiency (EPA, 1982a). Baghouses also collect fine particulates at high efficiency. High energy wet scrubbers are capable of collecting particulates less than 1 μm in size (EPA, 1982a). Examples of mass emissions test data for coal-fired boilers equipped with ESPs, scrubbers and baghouses are presented in Section 4 (Figure 4-2). Other sources of mass emissions data are listed in Section 3.

Step 4. Identify the Lowest Emission Limitation Achievable --

The percent reduction from baseline emissions (see Step 1 above) for each control option identified in Step 2 is calculated next. Estimated control efficiencies for total PM for dry bottom boilers burning bituminous coal as listed on Table 1.1-3 of EPA's Compilation of Air Pollutant Emission Factors (OAQPS, 1985) are as follows: Scrubber - 94 percent, ESP - 99.2 percent, and baghouse - 99.8 percent. Appendix C.2 of EPA's Compilation of Air Pollutant Emission Factors (OAQPS, 1985) presents typical collection efficiencies of various particulate control device for PM-10 emissions. Using the size distribution for uncontrolled emissions and the size specific control efficiency information presented in Appendix C.2 (OAQPS, 1985), the estimated collection efficiencies for PM-10 emissions are as follows: venturi scrubber - 94.7 percent, ESP - 98.0 percent, and baghouse - 99.4 percent. Therefore, the estimated achievable PM-10 emissions for each control technology are:

Venturi scrubber	-	9.5 kg/hr
ESP	-	3.6 kg/hr
Baghouse	-	1.1 kg/hr

Step 5. Identify the Current Lowest Emission Limitation --

Section 4 presents a summary of the most stringent state total PM limits. From information on Table 4-1, the most stringent total PM emission limit applicable to this size and type of boiler is determined from the following equation:

$$A = 0.05 \times I$$

where:

A = Allowable total PM emission rate in lb/hr

I = Heat input in MMBtu/hr

Therefore, the allowable limit is 8.1 lb/hr or 3.7 kg/hr. A closer review of this state emission limit confirms that this limitation applies to combustion units with the primary purpose of steam generation. There is also an applicable Federal NSPS for this source category. Although NSPS does not apply to the boiler in this case study (because it is an existing source), the NSPS limitation is technologically achievable, however, the limit may not be reasonable to achieve in all situations for existing sources. The NSPS limitation for a boiler with a heat input of 170.7 GJ/hr is 22 ng/J (0.05 lb/MMBtu); for the case study boiler, this equates to an emission limit of 3.76 kg/hr.

An equivalent PM-10 emission limitation is estimated as follows:

a. Percent control required to meet total PM limit:

$$\frac{777.6 - 3.7}{777.6} \times 100 = 99.5\%$$

b. Control technology that achieves 99.5 percent: baghouse. This is based on available information in OAQPS, 1985. Other sources of information (such as data provided by manufacturer's) may indicate that other control technologies can also achieve the required level of control.

c. Total PM emission rate achieved by selected technology:

$$777.6 \times (1-0.998) = 1.6 \text{ kg/hr}$$

d. Calculate "safety factor"; total PM limit divided by achievable total PM emission rate:

$$3.7 \div 1.6 = 2.3$$

e. Particle size distribution of uncontrolled exhaust stream (from Table 2-2):

$\% \leq 10\mu m$ - 23

$\% \leq 6\mu m$ - 17

$\% \leq 2.5\mu m$ - 6

f. Determine achievable PM-10 emission rate:

1.	Uncontrolled emission rates by size, kg/hr	$\leq 2.5\mu m$: 777.6 x 0.06 = 46.7	$\leq 6\mu m$: 777.6 x 0.17 = 132.2	$\leq 10\mu m$: 777.6 x 0.23 = 178.9
2.	Uncontrolled emission rates by size categories, kg/hr	0-2.5 μm: 46.7	2.5-6 μm: 85.5	6-10 μm: 46.7
3.	Control efficiencies of fabric filters by size category (from OAQPS, 1985, Appendix C.2), %	0-2.5 μm: 99	2.5-6 μm: 99.5	6-10 μm: 99.5
4.	Controlled emission rates by size category, kg/hr	0-2.5 μm: 46.7 x 0.01 = 0.47	2.5 = 6 μm: 85.5 x 0.005 = 0.43	6-10 μm: 46.7 x 0.005 = 0.23

Therefore, the achievable PM-10 emission rate:

$$0.47 + 0.43 + 0.23 = 1.1 \text{ kg/hr}$$

g. Multiply achievable PM-10 emission rate by "safety factor":

$$1.1 \times 2.3 = 2.5 \text{ kg/hr}$$

Therefore, 2.5 kg/hr is the equivalent PM-10 emission limit that requires 99.5 percent control (see step a above).

Case Study -- Economic Feasibility

Step 1. Develop Capital and Annual Costs --

The procedures used to develop capital and annual costs are described in detail in Section 5. Table 2-3 shows the capital cost calculations for a baghouse, the technologically feasible control technology that was identified above. Similarly, Table 2-4 shows the calculation of annual costs for the same baghouse.

Step 2. Calculate Cost Effectiveness --

Cost effectiveness is the annual cost of the control option divided by the quantity of PM-10 collected annually, expressed in dollars per Mg (ton). The cost effectiveness for the baghouse in the case study is determined as follows:

1. Quantity of PM-10 removed annually:

$$(178.9-1.1) \times 8{,}640 \times 10^{-3} = 1{,}536 \text{ Mg/yr}$$

where:

178.9 = Uncontrolled PM-10 emission rate, kg/hr

8,640 = Number of operating hours, hr/yr

10^{-3} = Converts kilograms to megagrams

2. Calculate cost effectiveness:

The cost effectiveness is calculated by dividing the annual cost, from Table 2-4 by the megagrams collected per year. Thus, for the baghouse:

$$\text{Cost effectiveness, \$/Mg} = \frac{400{,}800}{1{,}536} = 261$$

Step 3. Review of Economic Impacts/Affordability --

Should there be a claim that the RACT cannot be afforded for this source, the capital and annual costs and the cost effectiveness would be important considerations in evaluating the claim. Each non-affordability claim is unique and each must be evaluated individually using the guidelines presented under Step 3 -- Review of Affordability/Economic Impacts in the Economic Feasibility subsection.

TABLE 2-3. CASE STUDY: BAGHOUSE CAPITAL INVESTMENT

Cost Item	Cost, Thousand Dollars
DIRECT COSTS	
Purchased equipment[a]	
Baghouse and auxiliary equipment = A	186.9
Sales taxes = 0.03A	5.6
Freight = 0.05A	9.3
Instrumentation = 0.1 A	18.7
Purchased equipment cost = B	220.5
Installation costs[b]	
Foundation and supports = 0.04B	8.8
Handling and erection = 0.5B	110.3
Electrical = 0.08B	17.6
Piping = 0.01B	2.2
Insulation for duct work = 0.07B	15.4
Painting = 0.02B	4.4
Total direct cost	158.7
INDIRECT COSTS	
Engineering and supervision = 0.10B	22.1
Construction and field expenses = 0.20B	44.1
Contractor fees = 0.10B	22.1
Start=up = 0.01B	2.2
Performance test[c] = 0.01B	2.2
Contingencies[d] = 0.1B	22.1
Total indirect cost	114.8
TOTAL CAPITAL INVESTMENT	494.0

[a]Purchased equipment includes the baghouse plus auxiliaries such as fan, motor, starter, ductwork, dampers, screw conveyor, compressor, and stack.

[b]Site preparation and buildings would be included in the category if required.

[c]The performance test determines that all items of equipment are operating properly. It does not include the cost of determining that the control system emissions meet requirements; this is an operating expense.

[d]A contingency cost of 10 percent of purchased equipment was used since this is a retrofit installation.

TABLE 2-4. CASE STUDY: BAGHOUSE ANNUAL COSTS

Cost Item	Cost, Thousand Dollars
DIRECT ANNUAL COSTS	
Operating labor	
$\frac{2\ \text{hr}}{\text{shift}} \times \frac{3\ \text{shifts}}{\text{day}} \times \frac{360\ \text{days}}{\text{yr}} \times \frac{\$14}{\text{hr}} =$	30.2
Operating supervision at 15 percent of operating labor	4.5
Maintenance labor	
$\frac{1\ \text{hr}}{\text{shift}} \times \frac{3\ \text{shifts}}{\text{day}} \times \frac{360\ \text{days}}{\text{yr}} \times \frac{\$15.40}{\text{hr}} =$	16.6
Maintenance material at 100 percent of maintenance labor	16.6
Replacement bags[a]	
$[3{,}265 + (15{,}554 \times 1.08)]\,0.5762 =$	11.6
Utilities	
Electricity	
$0.00025164^{b} \times \frac{1{,}416\ \text{m}^3}{\text{min}} \times 261.6\ \text{mm}\ H_2O \times \frac{8{,}640\ \text{hr}}{\text{yr}} \times \frac{\$0.06}{\text{kWh}} =$	48.3
Compressed air (a pulse jet filter requires 25 $m^3/1{,}000\ m^3$ of gas filtered at a cost of \$5.65 per 1,000 sm^3)	
$\frac{25\text{m}^3}{1{,}000\ \text{m}^3} \times \frac{1{,}146\ \text{m}^3}{\text{min}} \times \frac{\$5.65}{1{,}000\ \text{sm}^3} \times \frac{60\ \text{min}}{\text{hr}} \times \frac{8{,}640\ \text{hr}}{\text{yr}} =$	8.3
Waste disposal at \$22/Mg, disposed of on site, assuming 100 percent collection efficiency	
$\frac{9.2\ \text{g}}{\text{m}^3} \times \frac{1{,}416\ \text{m}^3}{\text{min}} \times \frac{60\ \text{min}}{\text{hr}} \times \frac{8{,}640\ \text{hr}}{\text{yr}} \times \frac{1\ \text{Mg}}{10^6\ \text{g}} \times \frac{\$22}{\text{Mg}} =$	148.6
Total direct annual costs	284.7

(continued)

TABLE 2-4. (CONTINUED)

Cost Item	Cost, Thousand Dollars
INDIRECT ANNUAL COSTS	
Overhead	
60 percent (labor and maintenance materials) = 0.6 (30.2 + 4.5 + 16.6 +16.6) =	40.7
Insurance	
1 percent of capital investment = 0.01 (494.0) =	4.9
Property tax	
1 percent of total capital investment = 0.01 (494.0) =	4.9
Administrative charges	
2 percent of total capital investment = 0.02 (494.0) =	9.9
Capital recovery[c] = 0.1175 (494.0 - 3.3 - 15.6 x 1.08)	55.7
Total indirect annual costs	116.1
TOTAL ANNUAL COST	400.8

[a]The cost of replacement bags is $15,554. The 1.08 factor is for freight and sales taxes. For bag replacement labor, 10 minutes per bag for each of 795 bags was estimated. At a maintenance labor rate of $24.64 (including 60% overhead) the labor cost is $3,265 for 133 hours. The replacement cost was calculated using equation 5.1. The CRF in equation 5.1 was calculated using equation 5.4 for a two year bag life and 10 percent interest:

$$\text{CRF} = \frac{0.1\ (1+0.1)^2}{(1+0.1)^2-1} = 0.5762$$

[b]See equation 5.2a.

[c]For a 20 year equipment life and a 10 percent interest rate, CRF = 0.1175. The total capital investment (from Table 2-3) is reduced by the total cost for replacing the bags to avoid double counting.

Case Study -- Identify RACT

The results of the technological and economic feasibility determinations for the case study are summarized on Table 2-5.

TABLE 2-5. SUMMARY OF RACT DETERMINATIONS FOR CASE STUDY[a]

Parameter/technology	Fabric filter	ESP	Venturi scrubber	Process change
Uncontrolled emissions, kg/hr				
a. Total PM	777.6	777.6	777.6	777.6
b. PM-10	178.9	178.9	178.9	178.9
Controlled emissions, kg/hr				
a. Total PM	1.6	6.2	46.7	NA
b. PM-10	1.1	3.6	9.5	NA
Control effectiveness, %				
a. Total PM	99.8	99.2	94	NA
b. PM-10	99.4	98.0	94.7	NA
Current allowable emissions				
a. Total PM, kg/hr	3.7	3.7	3.7	
b. Opacity, %	0%[b]			
Equivalent PM-10 limit, kg/Mg	2.5			
Capital costs, $	494,000			
Annual costs, $/yr	400,800			
Cost effectiveness, $/Mg				
a. Total PM	59.80			
b. PM-10	260.90			
Energy requirement, mWh/yr	805.2			
Wastewater impact	None			
Solid waste impact	On-site landfill			
Other impacts	None			

[a]There may be slight differences in numbers due to rounding.

[b]0 percent, with exceptions for start-up, soot blowing, etc. See Section 4 for a more detailed discussion.

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SECTION 3

PROCESS EMISSIONS AND EMISSIONS CONTROL BIBLIOGRAPHY

This Section presents an annotated bibliography of information sources that describe the processes in each source category that generate PM-10 emissions, the magnitude of uncontrolled and controlled emissions from these sources, and emission control measures. The list of source categories is shown in the previous Section on Table 1-1.

The bibliography first shows general information sources that cover multiple source categories. They are arranged chronologically. The remaining information sources are arranged alphabetically by source category.

Most of the reports listed in this Section are available through the National Technical Information Service (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161; (703) 487-4650.

GENERAL INFORMATION SOURCES

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1973. Background Information for Proposed New Source Performance Standards: Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels, Secondary Lead Smelters and Refineries, Brass or Bronze Ingot Production Plants, Iron and Steel Plants, Sewage Treatment Plants; Volume 1 - Main Text. APTD-1352a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 72 pp.

Provides background information on the derivation of the proposed second group of New Source Performance Standards and their economic impact on the construction and operation of the plants listed in the title. This document contains test results.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1973. Background Information for Proposed New Source Performance Standards: Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels, Secondary Lead Smelters and Refineries, Brass or Bronze Ingot Production Plants, Iron and Steel Plants, Sewage Treatment Plants; Volume 2 - Appendix: Summaries of Test Data. APTD-1352b, PB229660, U.S. Environmental Protection Agency, Research Triangle Park, NC. 67 pp.

Volume 2 of previously described document.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Background Information for New Source Performance Standards: Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels, Secondary Lead Smelters and Refineries, Brass or Bronze Ingot Production Plants, Iron and Steel Plants, Sewage Treatment Plants. EPA 450/2-74-003, (APTD-1352c), U.S. Environmental Protection Agency, Research Triangle Park, NC. 151 pp.

Jutze, G.A., J.M. Zoller, T.A. Janszen, S. Amick, C.E. Zimmer, and R.W. Gerstle. 1977. Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions. EPA-450-3-77-010, PB272288, U.S. Environmental Protection Agency, Research Triangle Park, NC. 522 pp.

Provides guidelines for evaluating industrial process fugitive particulate emission sources relative to revisions to State Implementation Plans. Document includes section on control technologies.

Office of Air Pollution Control, Ohio Environmental Protection Agency. 1980. Reasonably Available Control Measures for Fugitive Dust Sources. Ohio Environmental Protection Agency, Columbus, OH. 596 pp.

Presents guidelines for selection of reasonably available control measures for fugitive dust sources for major manufacturing categories. Document includes discussions of process operations, particle characterization, control methods, efficiencies, and costs.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Control Techniques for Particulate Emissions from Stationary Sources; Volume 1, EPA-450/3-81-005a, PB83-127498, U.S. Environmental Protection Agency, Research Triangle Park, NC. 460 pp.

Presents information developments of control techniques which have become available since preparation of an earlier document entitled Control Techniques for Particulate Air Pollutants (AP-51). Includes sections on control technology and cost considerations.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Control Techniques for Particulate Emissions from Stationary Sources; Volume 2, EPA-450/3-81-005b, PB83-127480, U.S. Environmental Protection Agency, Research Triangle Park, NC. 540 pp.

Volume 2 of a previously described document.

Cowherd, C. Jr., and J.S. Kinsey. 1986. Identification, Assessment, and Control of Fugitive Particulate Emissions. EPA-600/8-86-023, U.S. Environmental Protection Agency, Washington, D.C. 180 pp.

Designed to assist national, state, and local control agency personnel and industry personnel in evaluating fugitive emission control plans and in developing cost-effective control strategies. The document includes sections on control alternatives, estimation of control system performance for process and open sources, estimating control costs and cost effectiveness, and development of fugitive emissions control strategies.

Steigerwald, Joseph. 1990. BACT/LAER Clearinghouse: A Compilation of Control Technology Determinations; Volume 1, EPA 450/3-90-015a, PB90-259722; Volume II - Appendix H, Source Codes 1 to 3, EPA 450/3-90-015b, PB90-259730; Volume III - Appendix H, Source Codes 4 to 6, EPA - 450/3-90-015C, PB90-259748; Volume IV - Appendix H, Source Codes 7 to 12, EPA - 450/3-90-015d, PB90-259755, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Provides State and local air pollution control agencies with current information on case-by-case control technology determinations that are made nationwide. The Clearinghouse is intended as a reference for State and local agencies in making BACT/LAER decisions.

Di Mauro, Desiree, Colleen Duffy. 1991. RACT/BACT/LAER Clearinghouse: A Compilation of Control Technology Determinations, First Supplement to 1990 Edition. EPA 450/3-91-015, PB91-231548, U.S. Environmental Protection Agency, Research Triangle Park, NC. 220 pp.

First Supplement to previously described document.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1991. Compilation of Air Pollution Emission Factors, AP-42, Supplements A, B, C and D. AP-42, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Presents process and control system descriptions and uncontrolled and controlled emissions data for numerous source categories.

ASPHALT AND ASPHALTIC CONCRETE PLANTS

Khan, Z.S., and T.W. Hughes. 1977. Source Assessment Asphalt Hot Mix. EPA-600/2-77-107n, PB-276731, U.S. Environmental Protection Agency, Cincinnati, OH. 173 pp.

Summarizes data on air emissions from the asphalt hot mix industry. Sections on control technology and process description are also provided.

Brooks, K.J., E.L. Keitz, and J.W. Watson. 1979. A Review of Standards of Performance for New Stationary Sources - Asphalt Concrete Plants. EPA-450/3-79-014, PB-298-427, U.S. Environmental Protection Agency, Research Triangle Park, NC. 138 pp.

Reviews the current standards of performance for new stationary sources; Subpart I - Asphalt Concrete Plans. Emphasis is given to the state of control technology and economic cost.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1985. Second Review of New Source Performance Standards - Asphalt Concrete Plants. EPA 450/3-85-024, PB86-126448, U.S. Environmental Protection Agency, Research Triangle Park, NC. 135 pp.

Reviews the current New Source Performance Standards for asphalt concrete plants. Includes section on applicable control technology.

Kinsey, J.S. 1986. Asphaltic Concrete Industry Particulate Emissions. Source Category Report. EPA/600/7-86-038, PB87-119574, U.S. Environmental Protection Agency, Research Triangle Park, NC. 335 pp.

Describes the development of particulate emission factors based on cutoff size for inhalable particles for the asphaltic concrete industry. Process and control technology descriptions are also provided.

BOILERS

McKenna, J.D., J.C. Mycock, and W.O. Lipscomb. 1975. Applying Fabric Filtration to Coal Fired Industrial Boilers (A Pilot Scale Investigation). EPA-650/2-74-058a, PB-245186, U.S. Environmental Protection Agency, Research Triangle Park, NC. 203 pp.

Gives results of a pilot scale investigation to determine the technoeconomic feasibility of applying a fabric filter dust collector to coal-fired industrial boilers. Includes sections on process description, controlled emissions, control technology, and annualized cost.

Boubel, R.W. 1977. Control of Particulate Emissions from Wood-Fired Boilers. PB-278-483/3, U.S. Environmental Protection Agency, Washington, DC.

Intended primarily as a guide for control agency personnel and engineers who are not familiar with wood-fired boilers. Includes sections on control technology and cost of control.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1978. Electric Utility Steam Generating Units, Particulate Matter - Background Information for Proposed Emission Standards. EPA-450/2-78-006a, PB-286224, U.S. Environmental Protection Agency, Research Triangle Park, NC. 174 pp.

Revised standards of performance for the control of emissions of particulate matter from electric utility power plants proposed under the authority of Section 111 of the Clean Air Act. Includes process description and economic impact assessments.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1978. Wood Residue Fired Steam Generator Particulate Matter Control Technology Assessment. EPA-450/2-78-044, PB80-196843, U.S. Environmental Protection Agency, Research Triangle Park, NC.

This document discusses the control equipment and emission limits which represent Best Available Control Technology (BACT).

Leavitt, C., K. Arledge, C. Shih, R. Orsini, W. Hamersma, R. Maddalone, R. Beimer, G. Richard, and M. Yamada. 1978. Environmental Assessment of Coal- and Oil-firing in a Controlled Industrial Boiler; Volume III - Comprehensive Assessment and Appendices. EPA-600/7-78-164c, PB291236, U.S. Environmental Protection Agency, Research Triangle Park, NC. 328 pp.

Gives results of a comparative multimedia assessment of coal versus oil-firing in a controlled industrial boiler, to determine relative environmental, energy, economic and societal impacts.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1979. Electric Utility Steam Generating Units - Background Information for Promulgated Emission Standards. EPA-450/3-79-021, PB-298510, U.S. Environmental Protection Agency, Research Triangle Park, NC. 339 pp.

Standards of performance for the control of particulate matter, sulfur dioxide, and nitrogen oxides emissions from electric utility steam generating units adopted under the authority of Section 111 of the Clean Air Act. Includes section on process description.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Fossil Fuel-Fired Industrial Boilers - Background Information. EPA-450/3-82-006a,b, PB82-202573, U.S. Environmental Protection Agency, Research Triangle Park, NC. 869 pp.

Provides background information for the fossil fuel-fired industrial boiler source category. Includes sections on uncontrolled emissions, control technologies, and cost impacts.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Nonfossil Fuel Fired Industrial Boilers - Background Information. EPA-450/3-82-007, PB82-203209, U.S. Environmental Protection Agency, Research Triangle Park, NC. 789 pp.

Provides background information about air emissions and emission controls, for the nonfossil fuel fired boiler source category. This document includes uncontrolled emissions of particulate matter, sulfur dioxide and nitrogen oxides, also includes control technologies and cost impacts of applying these control technologies.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1985. Summary of Regulatory Analysis New Source Performance Standards for Industrial-Commercial-

Institutional Steam Generating Units of Greater than 100 Million Btu/hr Heat Input. EPA-450/3-86-005, PB86-212099. U.S. Environmental Protection Agency, Research Triangle Park, NC. 276 pp.

Summarizes the regulatory analysis of New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units. Information on costs of controls and emission control technologies is included.

Energy and Environmental Analysis, Inc. 1989. Projected Impacts of Alternative New Source Performance Standards for Small Industrial-Commercial-Institutional Fossil Fuel-Fired Boilers. EPA-450/3-89-17, PB89-203723, U.S. Environmental Protection Agency, Research Triangle Park, NC. 139 pp.

Presents projected national environmental cost and energy impacts of alternative SO2 and particulate matter air emission standards for new small industrial-commercial-institutional steam generating units firing coal, oil, and natural gas. Includes sections on cost and cost effectiveness.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1989. Model Boiler Cost Analysis for Controlling Particulate Matter (PM) Emissions from Small Steam Generating Units. EPA-450/3-89-15, U.S. Environmental Protection Agency, Research Triangle Park, NC. 64 pp.

This report presents estimates of the cost and cost effectiveness associated with controlling particulate matter emissions from small coal-, oil-, and wood-fired industrial-commercial-institutional steam generating units.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1989. Projected Impacts of Alternative Particulate Matter New Source Performance Standards for Industrial-Commercial-Institutional Nonfossil Fuel-fired Steam Generating Units. EPA-450/3-89-18, U.S. Environmental Protection Agency, Research Triangle Park, NC. 13 pp.

Presents projected national environmental, cost and energy impacts of alternative particulate matter air emission standards for new small industrial-commercial-institutional steam generating units firing wood.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1989. Overview of the Regulatory Baseline, Technical Basis, and Alternative Control Levels for Particulate Matter (PM) Emission Standards for Small Generating Units. EPA-450/3-89-11, PB89-203715, U.S. Environmental Protection Agency, Research Triangle Park, NC. 31 pp.

Provides a summary of the technical data used in developing proposed New Source Performance Standards for small industrial-commercial-institutional steam generating units. Includes sections on emissions, process descriptions, and control technologies.

CALCINERS

Radian Corporation. 1980. Sodium Carbonate Industry-Background Information for Proposed Standards. EPA-450/3-80-029a, PB80-219678, U.S. Environmental Protection Agency, Research Triangle Park, NC. 358 pp.

Standards of performance to control emissions of particulate matter from new, modified, and reconstructed calciners, dryers and bleachers in natural process sodium carbonate plants as proposed under Section 111 of the Clean Air Act. Includes sections on emission control technology and economic impact analysis.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1985. Calciners and Dryers in Mineral Industries-Background Information for Proposed Standards. EPA-450/3-85-025a, PB86-196904, U.S. Environmental Protection Agency, Research Triangle Park, NC. 699 pp.

Standards of performance for the control of emissions from calciners and dryers in mineral industries proposed under the authority of Section 111 of the Clean Air Act. Contains section on economic impact assessments.

CHARCOAL PLANTS

Moscowitz, C.M. 1978. Source Assessment: Charcoal Manufacturing State of the Art. EPA-600/2-78-004Z, PB-290125, U.S. Environmental Protection Agency, Cincinnati, OH.

Document reviews the state of the art of air emissions from charcoal manufacture. Document includes process description, controlled emissions and control technology.

CHEMICAL MANUFACTURING PLANTS

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1975. Engineering and Cost Study of Air Pollution Control for the Petrochemical Industry; Volume 7 - Phthalic Anhydride Manufacture from Ortho-xylene. EPA-450/3-73-006g, PB245277, Research Triangle Park, NC.

This document is one of a series. This volume covers the manufacture of phthalic anhydride from ortho-xylene. Includes sections on process description, control technology and cost analysis.

Gerstle, R.W., and J.R. Richards. 1977. Industrial Process Profiles for Environmental Use, Chapter 4: Carbon Black Industry. EPA-600-2-77-023d, U.S. Environmental Protection Agency, Cincinnati, OH.

The catalog of Industrial Process Profiles for Environmental Use was developed as an aid in defining the environmental impacts of industrial activity in the United States. The carbon black industry is a distinctive part of the chemical industry, which processes hydrocarbon feedstocks into finely divided carbon black particle for use largely in tires, pigments, cement and cosmetics. Sections on process description and atmosphere emissions are included.

Serth, R.W., and T.W. Huges. 1977. Source Assessment: Carbon Black Manufacture. EPA-600/2-77-107k, PB-273-068/7, U.S. Environmental Protection Agency, Research Triangle Park, NC.

The report summarizes the assessment of air emissions from the manufacture of carbon black. The document includes a section on process description.

Shreve, R.N., and J.A. Brink, Jr. 1977. Chemical Process Industries. Fourth Edition. McGraw Hill Book Company. 814 pp.

Provides an overview of the chemical process industry. Includes discussions on various industries, uses and economics, unit operations and raw materials.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1977. Final Guideline Document: Control of Fluoride Emissions from Existing Phosphate Fertilizer Plants. EPA-450/2-77-005, PB265062, Research Triangle Park, NC.

Document serves as a text to state agencies in development of their gaseous fluoride emission regulations from existing phosphate fertilizer plants. Document includes information on control technology, emissions, and economic impact.

Radian Corporation. 1980. Sodium Carbonate Industry - Background Information for Proposed Standards. EPA-450/3-80-029a, PB80-219678, U.S. Environmental Protection Agency, Research Triangle Park, NC. 358 pp.

Standards of performance to control emissions of particulate matter from new, modified, and reconstructed calciners, dryers, and bleachers in natural process sodium carbonate plants as proposed under Section 111 of the Clean Air Act. Includes sections on emission control technology and economic impact analysis.

U.S. Environmental Protection Agency. 1980. Source Category Survey: Detergent Industry. EPA-450/3-80-030, PB80219678, Research Triangle Park, NC. 1978.

Standards of performance to control emissions of particulate matter from new, modified, and reconstructed calciners, dryers, and bleachers in natural process sodium carbonate plants. This document includes emission control technology, emissions, and economic impacts.

Kirk-Othmer. Kirk-Othmer Encyclopedia of Chemical Technology. 1982. John Wiley & Sons, Inc., New York, NY.

Provides a detailed discussion of chemical process technology.

COAL PREPARATION AND CLEANING PLANTS

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Coal Preparation Plants - Background Information for Standards of Performance; Volume 1 - Proposed Standards. EPA-450/2-74-021a, PB237421, U.S. Environmental Protection Agency, Research Triangle Park, NC. 58 pp.

Presents the proposed standards and the rationale for the degree of control selected. The document includes analysis of costs and economic impact.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Coal Preparation Plants - Background Information for Standards of Performance; Volume 2 - Test Data Summary. EPA-450/2-74-021b, PB237696, U.S. Environmental Protection Agency, Research Triangle Park, NC. 39 pp.

Presents the proposed standards and the rationale for the degree of control selected. Includes sections on sampling emissions and economic impact of standards.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1976. Coal Preparation Plants - Background Information for Standards of Performance; Volume 3 - Supplemental Information. EPA-450/2-74-021c, PB251618, U.S. Environmental Protection Agency, Research Triangle Park, NC. 62 pp.

Supplements information presented in two earlier background documents (EPA-450/2-74-021a and b) and is issued in connection with final promulgation of regulations for standards of performance for new and modified coal preparation plants. Document contains a summary of undated control costs.

TRW Energy Systems Group. 1980. A Review of Standards of Performance for New Stationary Sources for Coal Preparation Plants. EPA-450/3-80-022, PB82-193053, U.S. Environmental Protection Agency, Research Triangle Park, NC. 90 pp.

Reviews and assesses the need to revise the New Source Performance Standards for coal preparation plants. Includes sections on control technology and emissions.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1988. Second Review of New Source Performance Standards for Coal Preparation Plants. EPA-450/3-88-001, PB89-194237, U.S. Environmental Protection Agency, Research Triangle Park, NC. 73 pp.

The New Source Performance Standards for coal preparation plants were reviewed by the U.S. EPA for a second time. Includes section on control technology.

CONCRETE BATCH PLANTS

U.S. Environmental Protection Agency. 1975. Development Document for Effluent Limitations Guidelines and Standards of Performance, The Concrete Products Industries, Draft, Washington, DC.

COTTON SEED MILLING PLANTS

Monsanto Research Corporation. 1975. Source Assessment Document No. 27, Cotton Gins. EPA-600/2-78-004a, PB-280-024, U.S. Environmental Protection Agency, Research Triangle Park, NC.

This report describes a study of air pollutants from cotton gins. Document includes process description, emissions, and control technologies.

Enviro Control, Inc. 1980. Control Technology Assessment of Raw Cotton Processing Operations (Final Report). NIOSH-210-78-0001, PB82-186685, National Institute for Occupational Safety & Health, Cincinnati, OH. 367 pp.

Cotton dust control technology was assessed by conducting preliminary and detailed surveys of cotton ginning, cotton seed processing, yarn manufacturing, knitting, fabric weaving, and waste processing operations that use raw cotton.

Enviro Control, Inc. 1981. Use of Oil Additives (Liquid Oversprays) in Cotton Dust Control Technology (Final Report). PB82-177528, National Institute for Occupational Safety and Health, Cincinnati, OH. 68 pp.

Cotton dust control technology was assessed by conducting preliminary and detailed surveys of cotton ginning, cotton seed processing, yarn manufacturing, knitting, fabric weaving, and waste processing operations that use raw cotton.

FOUNDRIES

National Air Pollution Control Administration. 1970. Economic Impact of Air Pollution Controls on Gray Iron Foundry Industry. NAPCA publication-AP-74, NAPCA, Raleigh, NC. 124 pp.

Reviews the economic impact the four most common pollution devices (wet caps, multiple cyclones, wet scrubbers, fabric filters) have had on the Gray Iron Foundry Industry.

Fennelly, P., and P. Spawn. 1978. Air Pollution Control Techniques for Electric Arc Furnaces in the Iron and Steel Foundry Industry. EPA-450/2-78-024, PB283650, Research Triangle Park, NC.

This report provides guidance for evaluating air pollutant control technologies for EAF in the iron and steel foundry industry. Document contains sections of control technologies, emissions, and control technology cost.

Chmielewski, R.D., and S. Calvert. 1981. Flux Force/Condensation Scrubbing for Collecting Fine Particulate from Iron Melting Cupolas. EPA-600/7-81-148, PB82-196866, U.S. Environmental Protection Agency, Research Triangle Park, NC. 135 pp.

Gives results of a six month test, demonstrating the industrial feasibility of a flux/force condensation scrubbing system for controlling particulate emissions from an iron and steel melting cupola. Includes section on annual operating cost for scrubber system.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1981. Summary of Factors Affecting Compliance by Ferrous Foundries; Volume I - Text. EPA-340/1-80-021, Washington, DC.

Jeffrey, J., J. Fitzgerald, and P. Wolf. 1986. Gray Iron Foundry Industry Particulate Emissions: Source Category Report. EPA-600/7-86-054, PB87-145702, U.S. Environmental Protection Agency, Research Triangle Park, NC. 85 pp.

Gives the results of a study to develop particulate emission factors based on cutoff size for inhalable particles for the gray iron foundry industry.

Williams, R.L., and M. Duncan. 1986. Pilot Demonstration of the Air Curtain System for Fugitive Particle Control. EPA/600/7-86-041, PB87-132817, U.S. Environmental Protection Agency, Research Triangle Park, NC. 137 pp.

Gives results of the demonstration of the technical and economic feasibility of using an air curtain transport system to control buoyant fugitive particle emissions. Includes sections on control technology and controlled emissions.

GLASS MANUFACTURING PLANTS

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1979. Glass Manufacturing Plants - Background Information for Standards of Performance. EPA-450/3-79-005a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 278 pp.

A national emission standard for glass manufacturing plants as proposed under authority of Section 111 of the Clean Air Act. Document includes information on processes, control techniques, emissions and economic impacts.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1980. Glass Manufacturing Plants - Background Information for Promulgated Standards of Performance. EPA 450/3-79-005b, U.S. Environmental Protection Agency, Research Triangle Park, NC. 175 pp.

Standards of performance are being promulgated under Section 111 of the Clean Air Act to control particulate matter emissions from new, modified, and reconstructed glass manufacturing plants. Document covers public comments and testing data submitted during comment period.

Spinosa, E.D., and R.A. Holman. 1981. Chemical Analysis of Particle Size Fractions from Glass Melting Furnaces. EPA-600/2-81-015, PB81-160889, U.S. Environmental Protection Agency, Cincinnati, OH. 42 pp.

Identifies the size fraction distribution of the various chemical constituents of glass furnace emissions. Includes a section on control technology.

GRAIN MILLING OPERATIONS

Shannon, L.J., R.W. Gerstle, P.G. Gorman, D.M. Epp, T.W. Devitt, and R. Amick. 1973. Emissions Control in the Grain and Feed Industry; Volume I - Engineering and Cost Study. EPA-450/3-73-003a. U.S. Environmental Protection Agency, Research Triangle Park, NC. 544 pp.

Presents the results of a study of air pollution associated with the grain and feed industry.

Shannon, L.J., and P.G. Gorman. 1974. Emissions Control in the Grain and Feed Industry; Volume II - Emission Inventory. EPA-450/3-73-003b, PB241234, U.S. Environmental Protection Agency, Research Triangle Park, NC. 98 pp.

The emission information presented in "Volume I - Engineering and Cost Study" was used to calculate particulate emissions for each segment of the industry. This document includes a section on control technology.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1977. Standards Support and Environmental Impact Statement; Volume 1 - Proposed Standards of Performance for Grain Elevator Industry. EPA-450/2-77-001a, PB80-194152, U.S. Environmental Protection Agency, Research Triangle Park, NC. 348 pp.

Standards of performance to control particulate matter emissions from new and modified grain elevators in the U.S. as proposed under Section 111 of the Clean Air Act. Discussions on processes and emissions, control technologies, emission data, and economic impacts are included.

Office of Air Quality Planning and Standards, Emission Standards and Engineering Division, U.S. Environmental Protection Agency. 1978. Standards Support and Environmental Impact Statement; Volume 2 - Promulgated Standards of Performance for Grain Elevator Industry. EPA-450/2-77-001b, PB80-198435, U.S. Environmental Protection Agency, Research Triangle Park, NC. 92 pp.

Standards of performance for the control of particulate matter emissions from new, modified and reconstructed grain terminal elevators and certain storage elevators at grain processing plants promulgated under the authority of Section 111 of the Clean Air Act.

Midwest Research Institute. 1981. Source Category Survey: Animal Feed Dryers. EPA-450/3-81-017, PB82-151531, U.S. Environmental Protection Agency, Research Triangle Park, NC. 115 pp.

Presents the findings of a study to assess the need for New Source Performance Standards for animal feed dryers. Includes section on methods of air pollution control and their effectiveness.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1984. Review of New Source Performance Standards for Grain Elevators (Final Report). EPA-450/3-84-001, PB84-175744, U.S. Environmental Protection Agency, Research Triangle Park, NC. 105 pp.

Reviews the current standards of performance for new stationary sources: Subpart DD - Grain Elevators. Includes sections on control technology and economic costs.

GYPSUM PRODUCT MANUFACTURING AND PROCESSING PLANTS

Control Systems Division, U.S. Environmental Protection Agency. 1973. Screening Study for Background Information and Significant Emissions for Gypsum Product Manufacturing. EPA-RZ-73-286, PB-222736/1, Process Research, Inc., Cincinnati, OH. 52 pp.

The atmospheric emissions that are produced during the operation of calcining gypsum and production of gypsum board products are studied.

INCINERATORS

Helfand, R.M. 1979. A Review of Standards of Performance for New Stationary Sources for Incinerators. EPA-450/3-79-009, PB80-124787, U.S. Environmental Protection Agency, Research Triangle Park, NC. 64 pp.

Reviews the current Standards of Performance for New Stationary Sources: Subpart E - Incinerators. Includes information on the status of control technologies, processes, and emissions data.

Schindler, P. 1987. Municipal Waste Combustion Study: Emissions Database for Municipal Waste Combustors. EPA/530-SW-87-021b, PB87-206082, U.S. Environmental Protection Agency, Cary, NC.

This report describes an emission database compiled from tests conducted in U.S. and abroad. Results of controlled and uncontrolled testing programs are included.

Sedman, C.B., and T.G. Brna. 1987. Municipal Waste Combustion Study: Flue Gas Cleaning Technology. EPA/530-SW-87-021d, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Radian Corporation. 1988. Hospital Waste Combustion Study Data Gathering Phase, Final Report, PB89-148308, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Contains results of a study of air emissions from combustion of hospital waste. Document includes information on waste characterization, processes and equipment for combustion, control techniques, and air pollutants emitted.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1989. Municipal Waste Combustors - Background Information for Proposed Standards. 111(b) Model Plant Description and Cost Report. EPA-450/3-89-27b, PB90-154857, U.S. Environmental Protection Agency, Research Triangle Park, NC. 134 pp.

Twelve model plants are developed to represent the projected municipal waste combustor industry. Includes sections on operating and maintenance cost of control equipment, emission control options and control technology.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1989. Municipal Waste Combustors - Background Information for Proposed Standards. Post-Combustion Technology Performance. EPA-450/3-89-27c, PB90-154865, U.S. Environmental Protection Agency, Research Triangle Park, NC. 327 pp.

Evaluates the performance of various air pollution control devices applied to new and existing municipal waste combustors. Includes section on control technologies.

IRON AND STEEL FACILITIES

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Electric Arc Furnaces in the Steel Industry - Background Information for Standards of Performance; Volume 1 - Proposed Standards. EPA-450/2-74-017a, PB237-840, U.S. Environmental Protection Agency, Research Triangle Park, NC. 170 pp.

Provides background information and rationale used in the development of the proposed standard of performance. The economic and environmental impacts of the standard are discussed.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Electric Arc Furnaces in the Steel Industry - Background Information for Standards of Performance; Volume 2 - Summary of Test Data. EPA-450/2-74-017b, PB237-841, U.S. Environmental Protection Agency, Research Triangle Park, NC. 39 pp.

Summarizes test data from electric arc furnaces in the steel industry.

Bohn, R., T. Cuscino Jr., and C. Cowherd Jr. 1978. Fugitive Emissions from Integrated Iron and Steel Plants. EPA-600/2-78-050, U.S. Environmental Protection Agency, Research Triangle Park, NC. 276 pp.

Presents results of an engineering investigation of fugitive emissions in the iron and steel industry. Includes sections on sources, quantification, and control technology are presented.

Drabkin, M., and R. Helfand. 1978. A Review of Standards of Performance for New Stationary Sources for Iron and Steel Plants/Basic Oxygen Furnaces. EPA-450/3-78-116, PB289877, U.S. Environmental Protection Agency, Research Triangle Park, NC. 65 pp.

Reviews the current standards of performance for new stationary sources: Subpart N - Iron and Steel Plants/Basic Oxygen Furnaces. Includes sections on control technology and emissions.

VanOsdell, D.W., D. Marsland, B.H. Carpenter, C. Sparacino, and R. Jablin. 1979. Environmental Assessment of Coke By-Product Recovery Plants. EPA-600/2-79-016. U.S. Environmental Protection Agency, Research Triangle Park, NC. 387 pp.

Gives results of a screening study, initiating a multimedia environmental assessment of coke by-product recovery plants in the U.S. Provides process descriptions of recovery processes.

Westbrook, C.W. 1979. Level 1 Assessment of Uncontrolled Sinter Plant Emissions. EPA 600/2-79-112, U.S. Environmental Protection Agency, Washington, DC. 83 pp.

Gives results of sampling and analysis of uncontrolled emissions from two sinter plants, to characterize and quantify the particulate, organic, and inorganic species present. Process descriptions of the two plants are provided.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1979. Review of Standards of Performance for Electric Arc Furnaces in Steel Industry. EPA-450/3-79-033, U.S. Environmental Protection Agency, Research Triangle Park, NC. 50 pp.

The purpose of the document is to review the current New Source Performance Standards for electric arc furnaces in the steel industry and to assess the need for revision on the basis of developments that either have occurred or are expected to occur in the near future. The document provides descriptions of control technologies and their effectiveness as well as a discussion of the furnaces and their emissions.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Revised Standards for Basic Oxygen Process Furnaces - Background Information for Proposed Standards. EPA-450/3-82-005a, PB83166488, U.S. Environmental Protection Agency, Triangle Park, NC. 361 pp.

Discusses New Source Performance Standard for secondary emissions from basic oxygen process furnace steelmaking shops proposed under authority of Section 111 of the Clean Air Act. This document contains sections on emissions and control technology.

Spawn, P., and M. Jasinski. 1983. Envirotech/Chemico Pushing Emissions Control System Analysis. EPA-340/1-83-019, U.S. Environmental Protection Agency, Washington, DC. 103 pp.

Summarizes a study of the 21 Envirotech/Chemico one-spot, mobile pushing emissions control systems currently installed at coke plants operated by five domestic steel companies. System descriptions and emissions data are included.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1983. Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Industry - Background Information for Proposed Revisions to Standards. EPA-450/3-82-020a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 398 pp.

Discussions of Standards of Performance for the control of emissions from electric arc furnaces and argon-oxygen decarburization vessels in the steel industry being proposed under authority of Section 111 of the Clean Air Act. Sections on processes, pollutants, costs, emission capture and control technologies are included.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1985. Revised Standards for Basic Oxygen Process Furnaces - Background Information for Promulgated Standards. EPA-450/3-82-005b, PB86-145083, U.S. Environmental Protection Agency, Research Triangle Park, NC. 58 pp.

Discusses New Source Performance Standard for secondary emissions of particulate matter from basic oxygen process furnace (BOPF) steel-making shops being promulgated under authority of Section 111 of the Clean Air Act. This document contains sections on emissions and control technology.

United States Steel Corporation. The Making, Shaping and Treating of Steel, 10th Edition/Latest Technology. Association of Iron and Steel Engineers, Pittsburgh, PA. 1985. 1,511 pp.

Provides information relating to the latest technology and current practices used in making and processing steel.

Fitzgerald, J., J. Jeffery, and P. Wolf. 1986. Metallurgical Coke Industry Particulate Emissions: Source Category Report. EPA/600/7-85-050, PB87-140331, U.S. Environmental Protection Agency, Research Triangle Park, NC. 85 pp.

Presents results of a study to develop particulate emissions factors based on cutoff size for inhalable particles for the metallurgical coke industry. The report includes sections on a description of the industry and emission factors.

Jeffery, J., and J. Vay. 1986. Iron and Steel Industry Particulate Emissions: Source Category Report. EPA/600/7-86-036, PB87-119889, U.S. Environmental Protection Agency, Research Triangle Park, NC. 94 pp.

Presents results of a study to develop particulate emission factors based on cutoff size for inhalable particles for the iron and steel industry. Background information on the industry as well as emission factors are discussed.

LIME PLANTS

Industrial Gas and Cleaning Institute. 1973. Air Pollution Control Technology and Costs in Seven Selected Industries. EPA-450/3-73-010, PB-231757/6, U.S. Environmental Protection Agency, Research Triangle Park, NC. 724 pp.

Industrial Gas Cleaning Institute collected and formalized data on air pollution abatement in the following seven areas: Phosphate Fertilizer Manufacture, Feed & Grain Milling, Soap & Detergent Manufacture, Paint and Varnish Production, The Graphic Arts Industry, Lime Kiln Operation, and Gray Iron Foundry Cupola Operation. Includes process descriptions and information on pollutants, costs, and control technologies.

Office of Air Quality and Performance Standards, Emission Standards and Engineering Division, U.S. Environmental Protection Agency. 1977. Standards Support and Environmental Impact Statement; Volume 1 - Proposed Standards of Performance for Lime Manufacturing Plants. EPA-450/2-77-007a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 328 pp.

Standards of performance for the control of particulate matter emissions from affected facilities at new and modified lime manufacturing plants as proposed under the authority of Sections 111, 114, and 301(a) of the Clean Air Act. Document includes process information, control technologies, costs and economic impacts and test data.

Office of Air Quality and Performance Standards, Emission Standards and Engineering Division, U.S. Environmental Protection Agency. 1977. Standards Support and Environmental Impact Statement; Volume II - Standards of Performance for Lime Manufacturing Plants. EPA-450/2-77-007b, U.S. Environmental Protection Agency, Research Triangle Park, NC. 20 pp.

Appendices for previously described document.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1984. Lime Manufacturing Plants - Background Information for Promulgated Standards of Performance. EPA-450/3-84-008, PB84-191543, U.S. Environmental Protection Agency, Research Triangle Park, NC. 45 pp.

Standards of performance for the control of particulate matter emissions from rotary lime kilns at new, modified, or reconstructed lime manufacturing plants promulgated under the authority of Sections 111, 114, and 301(a) of the Clean Air Act, as amended. This report contains an economic impact study.

Kinsey, J.S. 1986. Lime and Cement Industry. Particulate Emissions: Source Category Report; Volume I - Lime Industry. EPA/600/7-86/031, PB87-103628, U.S. Environmental Protection Agency, Research Triangle Park, NC. 284 pp.

Presents results of a study to develop particulate emission factors based on cutoff size for inhalable particles for the lime industry. Process and control technology descriptions are also provided.

MARINE GRAIN TERMINALS

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1977. Standards Support and Environmental Impact Statement; Volume 1 - Proposed Standards of Performance for the Grain Elevator Industry. EPA-450/2-77-001a, PB80-194152, U.S. Environmental Protection Agency, Research Triangle Park, NC. 321 pp.

Standards of performance to control particulate matter emissions from new and modified grain elevators in the U.S. as proposed under Section 111 of the Clean Air Act. This document includes information on emission control technology and economic impacts.

GCA Corporation. 1984. Emission Factor Development for Ship and Barge Loading of Grain, U.S. Environmental Protection Agency, Research Triangle Park, NC.

METALLIC MINERALS PROCESSING PLANTS

Umlauf, G. & L.G. Wayne. 1977. Emission Factors and Emission Source Information for Primary and Secondary Copper Smelters. EPA-450/3-77-051, PB280377, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Describes procedures and methodology used in obtaining relevant information regarding these industries and the operational characteristics of process equipment used therein. Includes section on process description.

U.S. Environmental Protection Agency. 1978. Environmental Assessment of the Domestic Primary Copper, Lead and Zinc Industries, EPA-600/2-82-066, PB82-230913, Cincinnati, OH.

The report discusses the design, laboratory scale tests, construction, and field test of an improved metal-to-metal seal for coke-oven doors. Includes section on cost study.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Metallic Mineral Processing Plants -- Background Information for Proposed Standards; Volume 1: Chapters 1-9. EPA-450/3-81/009a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 488 pp.

This document provides background information and environmental and economic impact assessments of the regulatory alternatives considered in developing the proposed standards of performance for the control of particulate matter emissions from metallic mineral processing plants.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1984. Review of New Source Performance Standards for Primary Copper Smelters; Chapters 1-9. EPA-450/3-83-018a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 579 pp.

Contains background information and environmental and economic assessments considered in arriving at the conclusion that no changes should be made to the existing standard. Discussions on process descriptions, emissions, and control technologies for process and fugitive emissions are included.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1984. Review of New Source Performance Standards for Primary Copper Smelters; Appendices. EPA-450/3-83-018b, U.S. Environmental Protection Agency, Research Triangle Park, NC. 150 pp.

Appendices for previously described document.

NONMETALLIC MINERAL PROCESSING PLANTS

Blackwood, T.R., P.K. Chalekode, and R.A. Wachter. 1978. Source Assessment: Crushed Stone. EPA-600/2-78-004L, PB-284-029, U.S. Environmental Protection Agency, Cincinnati, OH. 94 pp.

Describes a study of atmospheric emissions from the crushed stone industry. Includes sections on emissions and control technology.

Chalekode, P.K., J.A. Peters, T.R. Blackwood & S.R. Archer. 1978. Emissions from the Crushed Granite Industry State of the Art. EPA-600/2-78-021, PB-281043, U.S. Environmental Protection Agency, Cincinnati, OH. 68 pp.

Describes a study of atmospheric emissions from the crushed granite industry.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Air Pollution Control Techniques for Nonmetallic Minerals Industry, EPA-450/3-82-014, PB83-105064, Research Triangle Park, NC.

Air pollution control technologies for the control of particulate emissions from non-metallic mineral processing plants are evaluated. Includes section on annualized emission control cost.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1983. Nonmetallic Mineral Processing Plants - Background Information for Proposed Standards. EPA-450/3-83-001a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 469 pp.

Standards of performance for the control of emissions from non-metallic mineral processing plants as proposed under the authority of Section 111 of the Clean Air Act. Includes section on economic impact.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1985. Nonmetallic Mineral Processing Plants - Background Information for Promulgated Standards. EPA-450/3-83-001b, U.S. Environmental Protection Agency, Research Triangle Park, NC. 92 pp.

Standards of performance for the control of particulate matter emissions from nonmetallic mineral processing plants are being promulgated under the authority of Section 111 of the Clean Air Act.

PAINT MANUFACTURING PLANTS

Industrial Gas Cleaning Institute. 1973. Air Pollution Control Technology and Costs in Seven Selected Industries. EPA-450/3-73-010, PB-231757/6, U.S. Environmental Protection Agency, Research Triangle Park, NC. 724 pp.

Industrial Gas Cleaning Institute collected and formalized data on air pollution abatement in the following seven areas: Phosphate Fertilizer Manufacture, Feed & Grain Milling, Soap & Detergent Manufacture, Paint & Varnish Production, The Graphic Arts Industry, Lime Kiln Operation, & Gray Iron Foundry Cupola Operation. Includes process descriptions and information on pollutants, costs, and control technologies.

Dowd, E. 1974. Air Pollution Control Engineering and Cost Study of the Paint and Varnish Industry. EPA-45013-74-031, U.S. Environmental Protection Agency, Research Triangle Park, NC. 442 pp.

Cottrell, H., S. Patel, and N. Falla. 1985. Air Pollution Audits in Industrial Paint Finishing: A Survey of Paint Related Air Pollution Problems in the UK (United Kingdom) Together with Recommended Abatement Methods.

PAINTRA-85/02/XAB, Paint Research Association, Teddington, England. 154 pp.

Monitoring exercises were conducted to determine air pollution problems associated with the industrial paint finishing industry.

PETROLEUM REFINERIES

Burklin, C.E. 1977. Revision of Emission Factors for Petroleum Refining. EPA-450/3-77-030, PB275685, U.S. Environmental Protection Agency, Research Triangle Park, NC. 85 pp.

Presents the results of an in-depth study to revise and update the emission factors and process descriptions presented in AP-42 for the petroleum refining industry. Includes section on controlled emission testing.

Barrett, K., and A. Goldfarb. 1979. A Review of Standards of Performance for New Stationary Sources for Petroleum Refineries. EPA-450/3-79-008, U.S. Environmental Protection Agency, Research Triangle Park, NC. 83 pp.

Reviews the current Standards of Performance for New Stationary Sources: Subpart J - Petroleum Refineries. Includes process information, uncontrolled emission data, achievable emission limits and control technologies.

Wetherold, R.G., and C.D. Smith. 1980. Assessment of Atmospheric Emissions from Petroleum Refining; Volume 2 - Appendix A. EPA-600/2-80-075a-d, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Gives results of a 3-year program to assess the environmental impact of petroleum refining atmospheric emissions.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1986. Review of New Source Performance Standards for Petroleum Refinery Fuel Gas. EPA-450/3-86-011, PB87-136966, U.S. Environmental Protection Agency, Research Triangle Park, NC. 87 pp.

As required by Section 111(b) of the Clean Air Act, as amended, a four year review of the New Source Performance Standards for petroleum refineries was conducted. No revisions are recommended. Includes section on control technology.

PHOSPHATE FERTILIZER PLANTS

Industrial Gas Cleaning Institute. 1973. Air Pollution Control Technology and Costs in Seven Selected Industries. EPA-450/3-73-010, PB-231858/6, U.S. Environmental Protection Agency, Research Triangle Park, NC. 724 pp.

Industrial Gas Cleaning Institute collected and formalized data on air pollution abatement in the following seven areas: Phosphate Fertilizer Manufacture, Feed and Grain Milling, Soap & Detergent Manufacture, Paint & Varnish Production, The Graphic Arts Industry, Lime Kiln Operation, and Gray Iron Foundry Cupola Operation. Includes section on cost of pollution control systems.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Phosphate Fertilizer Industry - Background Information for Standards of Performance; Volume 1 - Proposed Standards. EPA-450/2-74-019a, PB237606, U.S. Environmental Protection Agency, Research Triangle Park, NC. 148 pp.

Provides background information on the derivation of the standards of performance for the phosphate fertilizer industry. Includes sections on control technology and economic impact.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Phosphate Fertilizer Industry - Background Information for Standards of Performance; Volume 2 - Summary of Test Data. EPA-450/2-74-019b, PB237607, U.S. Environmental Protection Agency, Research Triangle Park, NC. 68 pp.

Provides background information on the derivation of the standards of performance for the phosphate fertilizer industry. Includes section on emissions.

Nyers, J.M., G.D. Rawlings, E.A. Mullen, C.M. Moscowitz, and R.B. Reznik. 1979. Source Assessment: Phosphate Fertilizer Industry. EPA/600/2-79/019C, PB-300681/4, Industrial Environmental Research Lab, Research Triangle Park, NC. 203 pp.

Describes a study of air emissions, water effluents, and solid residues resulting from the manufacture of phosphate fertilizers. Includes sections on emissions and control technology.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1980. Review of New Source Performance Standards for Phosphate Fertilizer Industry - Revised.

EPA-450/3-79-038R, PB81-122129, U.S. Environmental Protection Agency, Research Triangle Park, NC. 81 pp.

Determines that there is currently insufficient process experience and source test data to recommend New Source Performance Standards revisions at this time. Includes section on control technology.

PHOSPHATE ROCK PROCESSING PLANTS

Augenstein, D. M. 1978. Air Pollutant Control Techniques for Phosphate Rock Processing Industry. EPA-450/3-78-030, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Provides information on the control of particulate emissions from phosphate rock processing plants, including the typical and best demonstrated control techniques, the cost and environmental impacts of several levels of emission control for phosphate rock dryers, calciners, grinders, and ground rock handling systems, regulatory options, and enforcement aspects of potential regulations.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1979. Phosphate Rock Plants - Background Information for Proposed Standards. EPA-450/3-79-017, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Standards of Performance for phosphate rock plants are being proposed under the authority of Section 111 of the Clean Air Act. Emission Control Technologies, Environmental Impacts,and Economic Impacts are presented.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1979. Phosphate Rock Plants - Background Information; Volume 1 - Proposed Standards. EPA-450/3-79-017a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 375 pp.

Standards of Performance for the control of emissions from phosphate rock plants as proposed under the authority of Section 111 of the Clean Air Act. Process descriptions, emission control technologies, economic impacts, and test data are presented.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1982. Phosphate Rock Plants - Background Information for Promulgated Standards. EPA-450/3-79-017b, PB82-200460, U.S. Environmental Protection Agency, Research Triangle Park, NC. 49 pp.

Standards of performance for the control of particulate and visible emissions from phosphate rock plants promulgated under the authority of Section 111 of the Clean Air Act.

PLYWOOD, PARTICLE BOARD AND WAFERBOARD PLANTS

Pullman College of Engineering, Washington State University. 1972. Investigation of Emissions from Plywood Veneer Dryers (Revised Final Report). APTD-1144, PB-210583, Washington State University, WA. 141 pp.

The emissions from thirteen plywood dryers drying ten different species types were studied. Includes section on emissions.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1983. Control Techniques for Organic Emissions from Plywood Veneer Dryers. EPA-450/3-83-012, PB83-228247, U.S. Environmental Protection Agency, Research Triangle Park, NC. 113 pp.

Summarizes information gathered by the U.S. Environmental Protection Agency on the control of emissions from softwood plywood manufacturing. Includes sections on control technology and costs of controls. The emissions from thirteen plywood dryers drying ten different species types were studied. Includes section on emissions.

PORTLAND CEMENT PLANTS

Barrett, K.W. 1978. A Review of Standards of Performance for New Stationary Sources for Portland Cement Industry. EPA-450/3-79-012, PB80-112084, U.S. Environmental Protection Agency, Research Triangle Park, NC. 83 pp.

Reviews the current Standards of Performance for New Stationary Sources: Subpart F - Portland Cement Plants. Includes sections on control technologies and emissions.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1985. Portland Cement Plants - Background Information for Proposed Revisions to Standards. EPA 450/3-85-003a, PB86-100476, U.S. Environmental Protection Agency, Research Triangle Park, NC. 125 pp.

Contains a summary of the information gathered during the review of this New Source Performance Standard.

Kinsey, J.S. 1987. Lime & Cement Industry Particulate Emissions: Source Category Report; Volume II - Cement Industry. EPA 600/7-87/007, PB87-168654, U.S. Environmental Protection Agency, Research Triangle Park, NC. 410 pp.

Gives results of the development of particulate emission factors based on cutoff size for inhalable particles for the cement industry. Includes a process description.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1988. Portland Cement Plants - Background Information for Promulgated Revisions to Standards. EPA-450/3-85-003b, PB89-135966, U.S. Environmental Protection Agency, Research Triangle Park, NC. 64 pp.

Contains revisions to the monitoring, recordkeeping, and reporting requirements associated with standards of performance for portland cement plants.

PRIMARY ALUMINUM REDUCTION FACILITIES

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Primary Aluminum Plants - Background Information for Standards of Performance; Volume 1 - Proposed Standards. EPA-450/2-74-020a, U.S. Environmental Protection Agency, Research Triangle Park, NC. 122 pp.

Presents the proposed standards and the rationale for the degree of control selected.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1974. Primary Aluminum Plants - Background Information for Standards of Performance; Volume 2 - Summary of Test Data. EPA-450/2-74-020b, U.S. Environmental Protection Agency, Research Triangle Park, NC. 48 pp.

Presents the proposed standards and the rationale for the degree of control selected. This document includes section on economic impact.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1976. Primary Aluminum Industry - Background Information for Standards of Performance; Volume 3 - Supplemental Information. EPA 450/2-74-020c, U.S. Environmental Protection Agency, Research Triangle Park, NC. 50 pp.

Includes comments in response to the proposed regulation and EPA responses to these comments, updated economic impact information, and a discussion of problems encountered with the analytical method for sampling emissions.

Emission Standards and Engineering Division, U.S. Environmental Protection Agency. 1978. Background Information for Proposed Amendments to the New Source Performance Standard for the Primary Aluminum Industry. EPA-450/2-78-025a, PB82-242611, U.S. Environmental Protection Agency, Research Triangle Park, NC. 65 pp.

Supplements information contained in the preamble to proposed amendments for the New Source Performance Standard for the primary aluminum industry. Includes sections on emissions and cost.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1980. Primary Aluminum - Background Information for Promulgated Amendments. EPA 450/3-79-026, PB80-192479, U.S. Environmental Protection Agency, Research Triangle Park, NC. 26 pp.

Summarizes and responds to comments submitted by the public on the proposed amendments to the standards of performance for new primary aluminum plants. Includes section on economic impact.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1986. Review of New Source Performance Standards for Primary Aluminum Reduction Plants. EPA 450/3-86-010, PB87-131637/AS, U.S. Environmental Protection Agency, Research Triangle Park, NC. 121 pp.

Presents a summary of the current standards, the status of current applicable control technology, and the ability of the plants to meet the standards.

PULP MILLS

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1973. Atmospheric Emissions from the Pulp and Paper Manufacturing Industry. EPA-450/1-73-002, PB227181, U.S. Environmental Protection Agency, Research Triangle Park, NC. 120 pp.

Contains information on the nature and quantities of the atmospheric emissions from chemical pulping operations, principally the Kraft process. Includes sections on control techniques and emissions.

EKONO, Inc. 1976. Environmental Pollution Control in the Pulp and Paper Industry - Part I/Air. EPA-625/7-76-001, PB261708, U.S. Environmental Protection Agency, Cincinnati, OH.

Describes types, quantities, and sources of emissions presenting the latest control device alternatives, and estimates costs for implementing the air pollution control systems.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1976. Standard Support and Environmental Impact Statement; Volume 1 - Proposed Standards of Performance for Kraft Pulp Mills. EPA-450/2-76-014a. U.S. Environmental Protection Agency, Research Triangle Park, NC. 398 pp.

Standards of performance for the control of emissions of total reduced sulfur and particulate matter from new and modified kraft pulp mills as proposed under the authority of Section 111 of the Clean Air Act. Discussions on processes, control technologies, emission data, and economic impacts are included.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1977. Standard Support and Environmental Impact Statement; Volume II - Promulgated Standards of Performance for Kraft Pulp Mills. EPA-450/2-76-014b, PB278160, U.S. Environmental Protection Agency, Research Triangle Park, NC. 47 pp.

Standards of performance for the control of emissions of total reduced sulfur and particulate matter from new and modified kraft pulp mills promulgated under the authority of Section 111 of the Clean Air Act. Includes sections on emissions and economic effects.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1983. Review of New Source Performance Standards for Kraft Pulp Mills. EPA-450/3-83-017, PB84-154798, U.S. Environmental Protection Agency, Research Triangle Park, NC. 82 pp.

Reviews the current New Source Performance Standards for Kraft Pulp Mills. Includes section on control technology.

SECONDARY ALUMINUM REDUCTION FACILITIES

Brookman, E. T. 1978. Screening Study on Feasibility of Standards of Performance for Secondary Aluminum Manufacturing; Volume 1. EPA-450/3-79-037A, PB80-132954, U.S. Environmental Protection Agency, Washington, D.C. 156 pp.

The report contains background information on the secondary aluminum manufacturing industry. This report contains sections on production, processes and control techniques.

Brookman, E. T. 1978. Screening Study on Feasibility of Standards of Performance for Secondary Aluminum Manufacturing; Volume 2. EPA-450/3-79-037B, PB80-161284, U.S. Environmental Protection Agency, Washington, D.C. 214 pp.

Volume 2 of previously described document.

SUGAR PRODUCTION PLANTS

Cuscino, T. A., J. S. Kinsey, R. Hackney, R. Bohn, and R. M. Roberts. 1981. The Role of Agricultural Practices in Fugitive Dust Emissions. PB81-219073, ARB/R-81/138, Air Resources Board, State of California, Sacremento, CA. 264 pp.

The impact of agricultural operations on fugitive dust emissions were quantified for the San Joaquin Valley, the Sacramento Valley, and the Imperial Valley. Thirteen tests were performed to quantify emission factors from discing, land planning & vehicles traveling on unpaved farm roads. Also, six tests were performed to quantify emission factors from sugar beet harvesting.

Baker, R.A., and T. Lahre. 1977. Background Document Bagasse Combustion in Sugar Mills. EPA-450/3-77-007, U.S. Environmental Protection Agency, Research Triangle Park, NC. 45 pp.

Provides support for Section 1.8 of AP-2, Compilation of Air Pollution Emission Factors, Second Edition. It concerns the major criteria pollutants emitted during the combustion of baghouse in steam boilers.

SURFACE MINING OPERATIONS

Axetell, K., and C. Cowherd. 1981. Improved Emission Factors for Fugitive Dust from Western Surface Coal Mining Sources. OSM-242, PB90-177940, Office of Surface Mining Reclamation and Enforcement (DI), Washington, DC. 36 p.

The purpose of the study was to develop emission factors for significant surface coal mining operations that would be applicable to all Western mines and would be based on widely acceptable, state-of-the-art sampling and data analysis procedures.

Axetell, K. Jr., and C. Cowherd Jr. 1989. Improved Emission Factors for Fugitive Dust from Western Surface Coal Mining Sources; Volume 1 - Sampling Method/Test Results. PB90-179474, Office of Surface Mining Reclamation and Enforcement (DI), Washington, DC. 209 pp.

The primary purpose of the study was to develop emission factors for significant surface coal mining operations.

Axetell, K. Jr., and C. Cowherd Jr. 1989. Improved Emission Factors for Fugitive Dust from Western Surface Coal Mining Sources; Volume 2 - Emission Factors. PB90-179482, Office of Surface Mining Reclamation and Enforcement (DI), Washington, DC. 83 pp.

Volume 2 of previously described document.

Beyer, L.E., J.A. Diaper, and R.E. Nickel. 1989. Surface Mining and the Natural Environment: Technical Manual - Phase II. PB90-178856, Office of Surface Mining Reclamation and Enforcement (DI), Washington, DC. 327 pp.

Examines the process of surface mining: its potential impact on the natural environment, reclamation, and pollution control technologies used to minimize these impacts.

Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. 1989. Emission Factors and Control Technology for Fugitive Dust from Mining Sources/3rd Draft. PB90-177957, Office of Surface Mining Reclamation and Enforcement (DI), Washington, DC. 25 pp.

TURBINES (OIL-FIRED)

Shih, C.C., J.W. Hamersma, D.G. Ackerman, R.G. Beimer, M.L. Kraft, and M.M. Yamada. 1979. Emissions Assessment of Conventional Stationary Combustion Systems; Volume II - Internal Combustion Sources. EPA-600/7-79-029c, PB296390, U.S. Environmental Protection Agency, Research Triangle Park, NC. 239 pp.

Gives results of an assessment of emissions from gas - and oil-fueled gas turbines and reciprocating engines for electricity generation and industrial applications.

SECTION 4

ACHIEVABLE EMISSION LIMITS

INTRODUCTION

This Section discusses the most stringent mass and visible emission limits that can be routinely achieved for the source categories that are listed in Section 1. The most stringent achievable emission limits were determined by reviewing Federal and state regulations as well as available total particulate matter (PM) emissions test data. The achievable emission limits that are presented in this Section should be used as guidelines in determining RACT limit for particular sources.

Most states have not adopted limits specifically for PM-10. For this reason, the most stringent emission limits that are presented in the Section are for total PM. A suggested procedure to estimate an equivalent PM-10 emission limit is described in Section 2 (see page 2-5).

This Section is not intended to serve as a replacement for a review of applicable Federal and state regulations for a specific facility. The regulations cited here as the "most stringent" must be examined to determine their applicability to the particular facility being evaluated with respect to operating conditions, location, or other unique circumstances that may apply.

The format of the total PM emission limitations varies widely from state to state. The most common formats include:

- o Concentration - mg/dscm (gr/dscf), which may also be corrected to a specific percent oxygen, carbon dioxide, or excess air.
- o Emission rate - kg/hr (lb/hr), which is generally calculated by an equation or obtained from a table based on the production rate or, occasionally, air flow rate.
- o Production based rate - kg/Mg (lb/ton) of product or, in the case of fuel burning equipment, ng/J (lb/MMBtu).

For most source categories, it was impossible to choose a single state with the most stringent total PM emission limitation because of the variety of regulatory formats. Therefore, a discussion is included with each source category regarding the most stringent total PM emission limitation for each of the regulatory formats. However, the total PM emissions test data in this section are presented in mg/dscm (gr/dscf) or ng/J (lb/MMBtu) because most of the test data are presented in one of these two manners.

The format of visible emissions (VE) limitations also varies widely from state to state. Some states report the allowable limitation as an average, generally a 6-minute average, while other limitations are expressed in terms of an aggregate number of opacity readings that may exceed a specific value.

The state emission limits were determined by reviewing the state air regulations as printed in the Bureau of National Affairs (BNA) Environment Reporter (BNA, 1991a) as of October 25, 1991. Federal emission limits were determined by reviewing the New Source Performance Standards (NSPS) as they appear in the BNA Environment Reporter (BNA, 1991b), also as of October 25, 1991.

In many cases, the most stringent total PM and VE limitations only apply to new or modified sources or sources that are located in a certain area of the state, such as a nonattainment area or certain large metropolitan areas. For the purposes of determining the most stringent regulation, it was assumed that the emission source was located in the area of the state where the most stringent regulations apply.

The definition of new source varies from state to state and frequently even by source category within a state. Many states incorporate the Federal NSPSs into the state regulations, either by reference or by reiterating the emission limitations for the appropriate source categories. In these cases, the state "NSPS regulations" are described in the discussion for a given source category under the Federal NSPS regulations. Also, the time period for state classification of new sources ranges from the 1950's to the 1980's. In other words, a new source in one state may be considered an existing source in another state. Frequently an emission limit that applies to new sources in one state would apply to all sources in another state.

Although RACT, not NSPS, is required for existing sources, emission limits for new sources were included in the review because they are technologically achievable, however, the limits may not be reasonable to achieve in all situations for existing sources. As mentioned above, this section should not be seen as a replacement of a review of the regulations but should be used as a guideline to determine an achievable limit.

Several states have delegated authority to local agencies for implementing air pollution control programs. The most notable state in this category is California. Local agencies may also have different emission limitations (more stringent) than the state agency emission limitations. Local agency emission limitations were not included in this review. There may also be air pollution operating permit conditions or consent agreements that place stricter standards on sources. It was beyond the scope of this project to review all of these sources of information to determine the most stringent limitation.

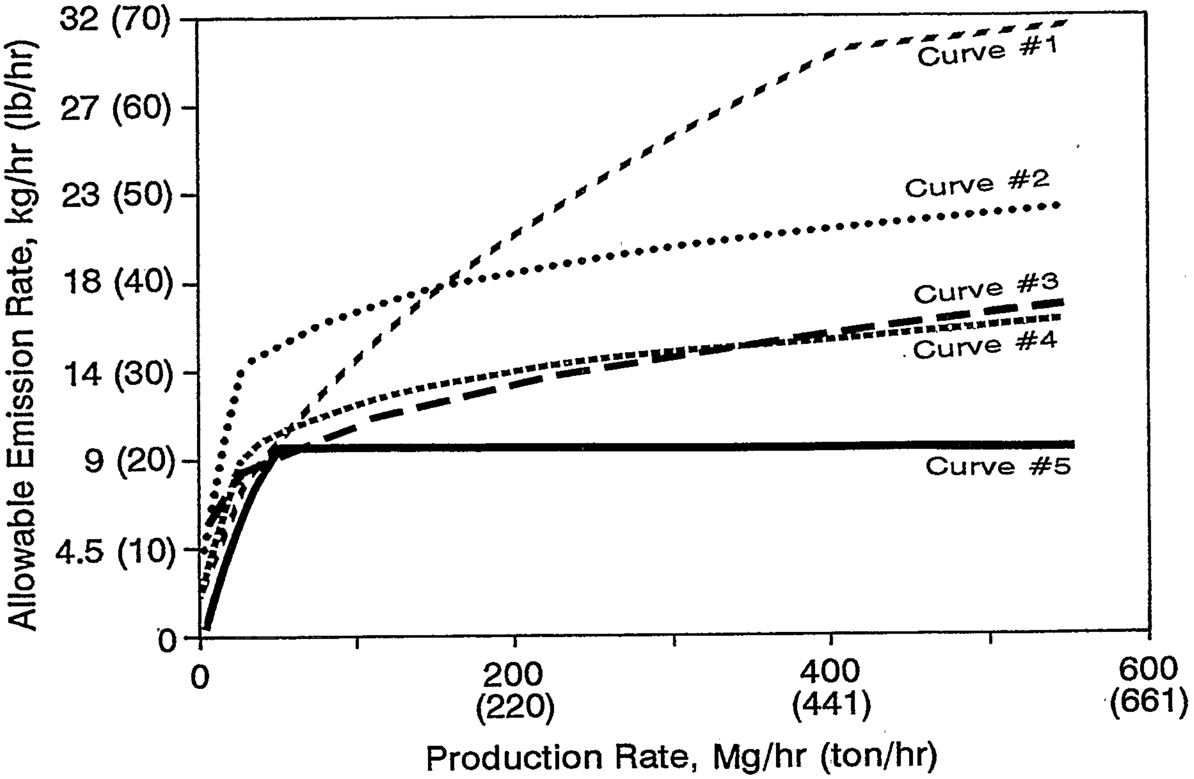
For most of the source categories, the strictest state total PM and VE limitations were determined by reviewing regulations for all fifty states. However, there are source categories that are not located in all fifty states, cotton milling, or iron and steel facilities, for example. For these types of source categories, the regulations were reviewed only for the states that were most likely to have these industries.

The total PM emissions test data for individual source categories were obtained from a variety of sources and are referenced with the discussion of the individual source category. Attempts were made to obtain total PM emissions test data from previous EPA data gathering projects or EPA published documents. The mass emission tests presented in this Section were generally conducted at existing, well-controlled facilities. The total PM emissions test data for an individual source category are by no means all inclusive; the test data are presented only to illustrate examples of emission rates achieved by existing well-controlled facilities.

The discussions in the remainder of this Section are arranged alphabetically by source category as shown on the list on Table 1-1 in Section 1. Each subsection has the following components: 1) most stringent state total PM limitations, 2) state VE limitations, 3) Federal NSPS requirements (if applicable) and 4) total PM emissions test data (if available). The state or states that have been identified as having the strictest regulations are shown in brackets. The discussion on individual source categories is preceded by a brief general discussion of emission rate limitations.

EMISSION RATE LIMITATIONS - GENERAL DISCUSSION

Many states use an equation related to process weight to determine the allowable total PM emission rate in kg/hr (lb/hr). This equation either applies to all industries within their state or to industries not otherwise explicitly regulated. The variable in the equation in almost all cases is the production rate. Figure 4-1 depicts the general curves that produce the most stringent total PM emission limitations. As shown on Figure 4-1, no one curve can be used to determine the most stringent



Curve #1: $E = A(P)^B$; where E is the allowable rate (lb/hr), A is 2.54 for production rates up to 450 ton/hr and 24.8 for production rates > 450 ton/hr, P is production rate (ton/hr), and B is 0.534 for production rates up to 450 ton/hr and 0.16 for production rates > 450 ton/hr [IL].

Curve #2: For production rates < 30 ton/hr: $E = 3.59\ P^{0.62}$; where E is the allowable rate (lb/hr) and P is production rate (ton/hr). For production rates > 30 ton/hr: $E = 17.31\ P^{0.16}$ [many states].

Curve #3: For production rates > 9,250 lb/hr: $E = 1.10(PW)^{0.25}$; where E is the allowable rate (lb/hr) and PW is production rate (lb/hr) [ID].

Curve #4: For production rates > 30 ton/hr: $E = 0.5(55P^{0.11} - 40)$; where E is the allowable rate (lb/hr) and P is production rate (ton/hr). For production rates < 30 ton/hr: determined from table in state regulations [MA].

Curve #5: Applies only to certain operations which undergo a chemical change. Values are from a table in state regulations [WV].

Figure 4-1. Summary of most stringent state total PM emission rate equations.

emission rate limitation because of the change in the equation with production rate. Figure 4-1 is referenced as needed in the individual source category discussions that follow.

ASPHALT AND ASPHLATIC CONCRETE PLANTS

Total PM emission limitations for asphalt concrete plants for all fifty states were reviewed. There is also an applicable NSPS (Subpart I) emission limitation for this source category.

The following is a summary of the most stringent state total PM emissions limitations:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [NY, IN, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than or equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - The most stringent emission rate results from the following equation: $A = 0.76(6W)^{0.42}$; where A is the allowable rate (lb/hr) and W is the production rate (ton/hr) [PA].

- Production based rate - 0.05 kg/Mg (0.1 lb/ton) of product [CT].

The most stringent state VE limitation is for certain areas of Maryland which are allowed no VE.

NSPS Subpart I applies to hot mix asphalt facilities that commenced construction or modification after June 11, 1973. Atmospheric total PM discharges can not contain more than 90 mg/dscm (0.04 gr/dscf) or exhibit 20 percent opacity or greater.

Examples of total PM emissions test data from well controlled facilities is summarized below (Fitzpatrick, *et al*, 1991; OAQPS, 1973; OAQPS, 1974a, OAQPS, 1985a):

	Cyclone/Baghouse	Cyclone/Scrubber
Number of tests	13	8
Number of facilities	13	8
Maximum, mg/dscm (gr/dscf)	98.8 (0.043)	94.2 (0.0410)
Minimum, mg/dscm (gr/dscf)	10.1 (0.0044)	28.0 (0.0122)
Average, mg/dscm (gr/dscf)	38.1 (0.0166)	56.9 (0.0248)

BOILERS

For the purposes of this document, utility boilers are defined as a unit with a heat input that is greater than 105 GJ/hr (100 MMBtu/hr), and industrial/commercial boilers as those units with a heat input that is greater than 0.5 GJ/hr (0.5 MMBtu/hr) and less than or equal to 105 GJ/hr (100 MMBtu/hr). Individual states and Federal NSPS regulations may define utility and industrial/commercial boilers differently.

Total PM regulations for all fifty states were reviewed for utility and industrial/commercial boilers burning coal, wood, and residual fuel oil. Many of the state regulations are calculated using an equation with the boiler's rated heat input as a variable. In order to determine the strictest state regulation, a boiler with a heat input of 270 GJ/hr (260 MMBtu/hr) was selected to represent a utility boiler and a boiler with a heat input of 105 GJ/hr (100 MMBtu/hr) was selected to represent an industrial/commercial boiler.

The strictest total PM emission limitations, by type of fuel, are summarized on Table 4-1.

The most stringent state VE limitations are as follows:

- No visible emissions, with exceptions for startup, soot blows, etc. [MD].
- If the emissions can be reasonably controlled, opacity shall not exceed 20% for more than 2 minutes per hour and shall not exceed 40 percent at any time [MA].
- Not greater than or equal to 40 percent at any time and not greater than or equal to 20 percent for 3 or more minutes per hour [NY].

NSPS Subparts D, Da, Db, and Dc apply to boilers. Subpart D applies to fossil fuel-fired units that are greater than 264 GJ/hr (250 MMBtu/hr) on which construction or modifications commenced after August 17, 1971. The total PM emission limitation is 43 ng/J (0.10 lb/MMBtu) and opacity can not exceed 20 percent except for one 6-minute period per hour when it can not exceed more than 27 percent.

Subpart Da applies to electric utility steam generating units that are greater than 264 GJ/hr (250 MMBtu/hr) that commenced construction or modification after September 18, 1978. The total PM emission limitation is 13 ng/J (0.03 lb/MMBtu). VE shall not exceed 20 percent except for one 6-minute period per hour which can not exceed 27 percent opacity.

TABLE 4-1. SUMMARY OF STRICTEST TOTAL PM EMISSIONS LIMITATIONS FOR BOILERS

	Utility[a] Boiler	Industrial/Commercial[b] Boiler
<u>Coal</u>		
Concentration	69 mg/dscm (0.03 gr/dscf) [MD]	114 mg/dscm[c] (0.05 gr/dscf) [AK, ID, MD]
Emission rate	Calculated using the following equation for steam generating units: A = 0.05 x I; where I is heat input in MMBtu/hr and A is the allowable rate in lb/hr [WV]	Calculated using the following equation for non-steam generating units: A = 0.09 x I; where I is heat input in MMBtu/hr and A is the allowable rate in lb/hr [WV]
Production-based rate	22 ng/J (0.05 lb/MMBtu) [ME, MA, NM]	43 ng/J (0.10 lb/MMBtu) [IL, MA, MI, MN, WY]
NSPS	13 ng/J (0.03 lb/MMBtu)	22 ng/J (0.05 lb/MMBtu)
<u>Residual Oil</u>		
Concentration	46 mg/dscm (0.020 gr/dscf) [MD]	46 mg/dscm (0.020 gr/dscf) [MD]
Emission rate	Calculated using the following equation for steam generating units: A = 0.05 x I; where I is heat input in MMBtu/hr and A is the allowable rate in lb/hr [WV]	Calculated using the following equation for non-steam generating units: A = 0.09 x I; where I is heat input in MMBtu/hr and A is the allowable rate in lb/hr [WV]
Production-based rate	13 ng/J (0.03 lb/MMBtu) [NM]	34 ng/J (0.08 lb/MMBtu) [ME]

(Continued)

TABLE 4-1. (CONTINUED)

		Utility[a] Boiler	Industrial/Commercial[b] Boiler
	NSPS	13 ng/J (0.03 lb/MMBtu)	43 ng/J (0.10 lb/MMBtu)
<u>Wood</u>	Concentration	69 mg/dscm (0.03 gr/dscf) [MD]	69 mg/dscm (0.05 gr/dscf) [AK, MD]
	Emission rate	Calculated using the following equation for steam generating units: A = 0.05 x I; where I is heat input in MMBtu/hr and A is the allowable rate in lb/hr [WV]	Calculated using the following equation for non-steam generating units: A = 0.09 x I; where I is heat input in MMBtu/hr and A is the allowable rate in lb/hr [WV]
	Production-based rate	26 ng/J (0.06 lb/MMBtu) [ME]	34 ng/J (0.08 lb/MMBtu) [ME]
	NSPS	13 ng/J (0.10 lb/MMBtu)	43 ng/J (0.10 lb/MMBtu)

[a]Utility boiler is represented by a unit with a rated heat input of 270 GJ/hr (260 MMBtu/hr).
[b]Industrial/commercial boiler is represented by a unit with a rated heat input of 105 GJ/hr (100 MMBtu/hr).
[c]Corrected to 8 percent oxygen in Idaho.

NSPS Subpart Db applies to industrial, commercial, and institutional steam generating units that are greater than 105 GJ/hr (100 MMBtu/hr) and commenced construction or modification after June 19, 1984. For facilities burning coal, the total PM emission limitation is 22 ng/J (0.05 lb/MMBtu). Oil-fired and wood-fired units are limited to 43 ng/J (0.10 lb/MMBtu). Visible emission shall not exceed 20 percent except for one 6-minute period per hour which shall not exceed 27 percent.

Subpart Dc applies to small industrial, commercial, and institutional steam generating units that commenced construction or modification after June 9, 1989. For coal-fired units that are greater than or equal to 32 GJ/hr (30 MMBtu/hr) and less than or equal to 105 GJ/hr (100 MMBtu/hr), the total PM emission limit is 22 ng/J (0.05 lb/MMBtu). The limit for wood-fired boilers in the same size range is 43 ng/J (0.10 lb/MMBtu). Opacity for coal oil, and wood-fired units shall not exceed 20 percent except for one 6-minute period per hour which shall not exceed 27 percent.

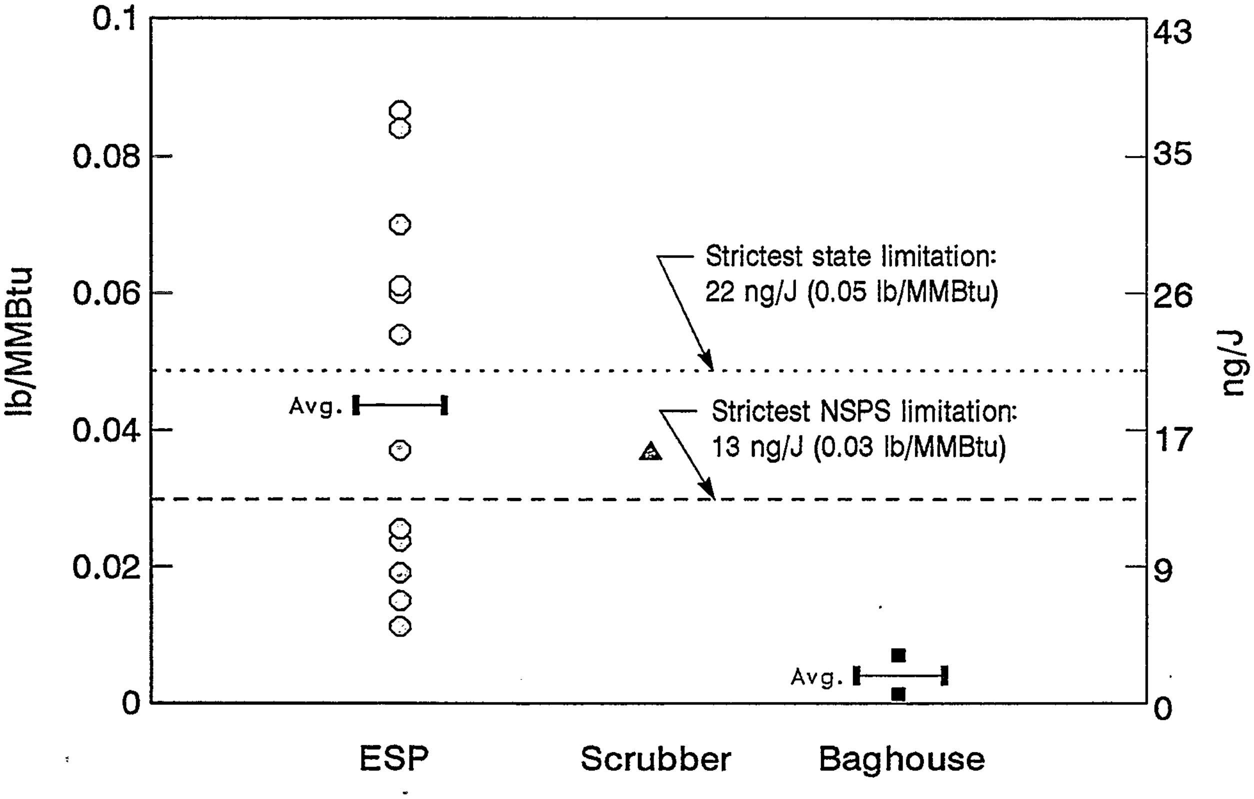
Examples of total PM emissions data for coal-fired utility boilers are depicted on Figure 4-2. (Fitzpatrick, *et al*, 1991). Data for wood-fired boilers is summarized below (Fitzpatrick, *et al*, 1991. All boilers are greater than 105 GJ/hr (100 MMBtu/hr).

Wood-Fired Boilers

	Multiclones/ electro-scrubber	Cyclone/ wet scrubber	Baghouse
Number of tests	1	5	1
Number of facilities	1	5	1
Maximum, ng/J (lb/MMBtu)	12.0 (0.028)	42 (0.098)	4.3 (0.01)
Minimum, ng/J (lb/MMBtu)	12.0 (0.028)	15.1 (0.035)	4.3 (0.01)
Average, ng/J (lb/MMBtu)	12 (0.028)	30.1 (0.07)	4.3 (0.01)

BRICK MANUFACTURING PLANTS

Regulations for all fifty states were reviewed to determine the strictest total PM and visible emissions limitations for brick kilns. The most stringent total PM emissions limitations for brick kilns are:



	ESP	Scrubber	Baghouse
Number of tests	12	1	2
Number of facilities	9	1	2
Maximum, ng/J (lb/MMBtu)	97.9 (0.0865)	84.7 (0.037)	16.0 (0.007)
Minimum, ng/J (lb/MMBtu)	25.6 (0.0112)	84.7 (0.037)	29.7 (0.013)
Average, ng/J (lb/MMBtu)	105.3 (0.046)	84.7 (0.037)	22.9 (0.010)

Figure 4-2. Examples of total PM emissions test data for coal-fired utility boilers.

- Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - The emission limitation varies by production rate; refer to Figure 4-1.

The most stringent state VE limitation is for certain areas of Maryland which are allowed no VE.

CALCINERS

Regulations for all fifty states were reviewed to determine the most stringent total PM and VE limitations for calciners. The most stringent total PM regulations are as follows:

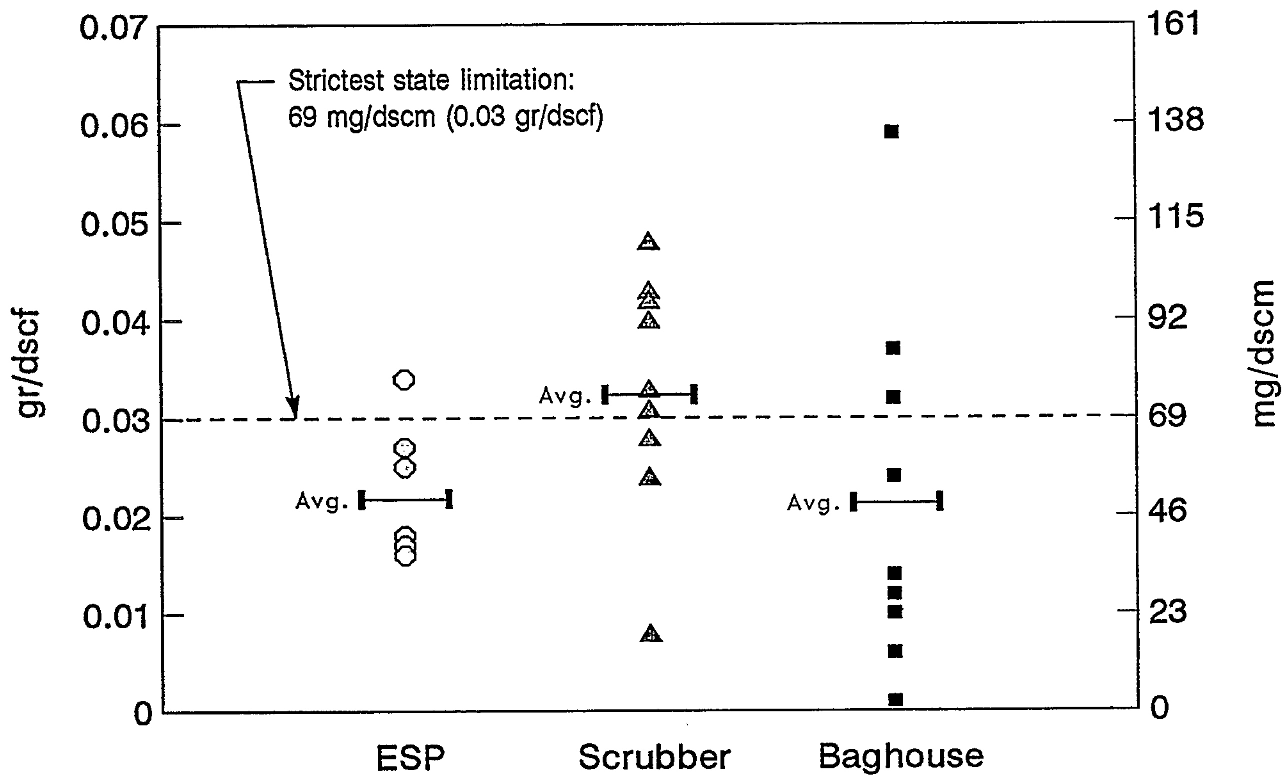
- Concentration - 69 mg/dscm (0.03 gr/dscf) [MD, FL]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - The most stringent emission rate for a 18 Mg/hr (20 ton/hr) calciner is calculated by the following equation: $A = 0.62\ P$; where A is the allowable rate in lb/hr and P is production rate in ton/hr [NV]. This regulation has a maximum allowable emission rate of 4.8 kg/hr (10.50 lb/hr). This regulation applies specifically to calciners at colemanite flotation processing plants. Refer to Figure 4-1 for the most stringent limitation for other calciners.

The most stringent state opacity standard is for certain areas of Maryland which are allowed no visible emissions.

NSPS Subpart NN applies to calciners at phosphate rock plants. The standards will be discussed in the subsection on phosphate rock processing plants.

Available total PM emissions test data for calciners is summarized on Figure 4-3 (Fitzpatrick, *et al*, 1991; OAQPS, 1985b).



	ESP	Scrubber	Baghouse
Number of tests	7	9	9
Number of facilities	5	9	8
Maximum, mg/dscm (gr/dscf)	77.8 (0.034)	109.8 (0.048)	135.0 (0.059)
Minimum, mg/dscm (gr/dscf)	36.6 (0.016)	18.3 (0.008)	2.3 (0.001)
Average, mg/dscm (gr/dscf)	50.3 (0.022)	75.5 (0.033)	50.3 (0.022)

Figure 4-3. Examples of total PM emissions test data for calciners.

CHARCOAL PLANTS

Regulations in all fifty states for charcoal plants were reviewed. The strictest total PM emissions standards are:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - Varies by production rate; refer to Figure 4-1.

The most stringent VE limitation is 0 percent [MD].

CHEMICAL MANUFACTURING PLANTS

Regulations were reviewed for all fifty states to determine the strictest total PM and opacity emission limitations for reactors, blenders, and mixers at chemical manufacturing plants. The most stringent general total PM emissions limitations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf)[FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - For an operation that results in a chemical change in the material of origin, the most stringent mass regulation is a value that varies by production rate that is determined from Curve 5 on Figure 4-1 [WV]. For a operation that involves a physical change in the material of origin, refer to Figure 4-1.

The most stringent VE limitation is 0 percent opacity [MD].

COAL PREPARATION AND CLEANING PLANTS

Regulations for all fifty states were reviewed to determine the most stringent total PM and opacity limitations for coal preparation and cleaning plants. A Federal NSPS also applies to this source category.

The most stringent state total PM emission limitations for thermal coal dryers are:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Also, several states have a similar limitation of 70 mg/dscm (0.031 gr/dscf) [AZ, KY, and MN]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - The most stringent emission rate is calculated using the following equation: $A = 0.76(2\ W)^{0.42}$; where A is the allowable emission rate (lb/hr) and W is production rate (ton/hr) [PA].

The most stringent state total PM regulations for pneumatic coal-cleaning equipment (air tables) are:

- Concentration - 40 mg/dscm (0.018 gr/dscf) [AZ, KY, MN].

- Emission rate - The most stringent emission rate is calculated using the following equation: $A = 0.76(2\ W)^{0.42}$; where A is the allowable emission rate (lb/hr) and W is production rate (ton/hr) [PA].

The most stringent state opacity limitation is 0 percent [MD]. Fugitive emissions are also limited to none [PA].

NSPS Subpart Y applies to coal preparation plants which process more than 181 Mg/day (200 ton/day) and were constructed or modified after October 24, 1974. The total PM limitation for thermal dryers shall not exceed 70 mg/dscm (0.031 gr/dscf) and 20 percent opacity or greater. Total PM emissions from pneumatic coal-cleaning equipment shall not exceed 40 mg/dscm (0.018 gr/dscf) and 10 percent opacity or greater. Coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems shall not discharge 20 percent opacity or greater.

Total PM emissions data from three pneumatic coal-cleaning facilities equipped with baghouses ranges from 11 to 123 mg/dscm (0.005 to 0.0536 gr/dscf) with an average of 50 mg/dscm (0.022 gr/dscf. (Fitzpatrick, *et al* 1991; OAQPS, 1974b). Total PM emissions data from six facilities with thermal dryers controlled with multiclones and scrubbers ranged from 29 to 75 mg/dscm (0.0128 to 0.0327 gr/dscf) with an average concentration of 47 mg/dscm (0.0204 gr/dscf) (OAQPS, 1974b).

CONCRETE BATCH PLANTS

Total PM and visible emissions limitations for all fifty states were reviewed to determine the strictest limitations for concrete batch plants. The most stringent total PM emissions limitations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - the most stringent standard depends on production rate; see Figure 4-1 for a graphical illustration of the standards.

- o Production-based rate - 11.9 g/m^3 (0.021 lb/yd^3) concrete.

Visible emissions are limited to 0 percent [MD].

COTTON SEED MILLING PLANTS

State regulations for Alabama, Arizona, Arkansas, Georgia, Louisiana, Mississippi, Oklahoma, South Carolina, Tennessee, and Texas were reviewed to determine the most stringent total PM and opacity limitations for cotton seed milling.

State regulations are all expressed as an emission rate which varies by production rate. The strictest total PM emission rate limitations can be determined as follows.

- o For operations less than 1.4 Mg/hr (3,000 lb/hr): $A = 3.12P^{0.985}$; where A is the allowable rate (lb/hr) and P is production rate (ton/hr) [AL, TX].

- o For operations between 1.4 and 27 Mg/hr (3,000 and 60,000 lb/hr): $A = 3.59P^{0.62}$; where A is the allowable rate (lb/hr) and P is production rate (ton/hr) [TN].

- o For operations between 27 and 36 Mg/hr (60,000 and 80,000 lb): $A = 17.31P^{0.16}$; where A is the allowable rate (lb/hr) and P is production rate (ton/hr) [TN]

- o For operations above 36 Mg/hr (80,000 lb/hr): 14.6 kg/hr (31.2 lb/hr) [SC].

The strictest state VE standard states that opacity shall not be greater than equal to 20 percent after any manufacturing process [AR]. Another state stipulates the VE shall not exceed 20 percent for more than an aggregate of 5 minutes per hour and not more than 20 minutes per 24 hours [TN].

FOUNDRIES

Regulations for all fifty states were reviewed to determine the most stringent total PM and VE standards for grey iron foundries, aluminum foundries, and steel shredders.

The most stringent total emission standards for grey iron foundries are as follows:

- Concentration - 50 mg/dscm (0.022 gr/dscf) [NH]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - For operations greater than 41 Mg/hr (45 ton/hr), the most stringent emission rate is calculated by the following equation: $A = 1.10(PW)^{0.25}$; where A is the allowable rate (lb/hr) and PW is production rate (lb/hr) [ID]. For operations less than 41 Mg/hr (45 ton/hr) the most stringent allowable rate is calculated as follows: $E = 2.54\ (P)^{0.534}$, where E is allowable rate (lb/hr) and P is production rate (ton/hr) [IL].

- Production-based rate - 0.85 kg/Mg (1.7 lb/ton) of iron or a 90 percent reduction.

Total PM emission test data is available for nine grey iron facilities equipped with baghouses. The average results are 14.9 mg/dscm (0.0065 gr/dscf) with a range of 5.5 to 58.8 mg/dscm (0.0024 to 0.0257 gr/dscf) (Fennelly, 1978; Fitzpatrick, *et al*, 1991).

The strictest total PM emission limitations for aluminum foundries and shredders are as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - Allowable rates varies by production rate; refer to Figure 4-1.

The most stringent state opacity standard for foundries is 0 percent [MD].

GLASS MANUFACTURING PLANTS

Regulations for all fifty states were reviewed to determine the most stringent total PM emissions and opacity regulations. A Federal NSPS also applies to this source category.

The most stringent state total PM emission regulations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) for production rates greater than 45 Mg/hr (50 ton/hr) [NY].

- o Emission rate - Allowable emission rates vary by production rate; refer to Figure 4-1.

- o Process-based rate - 0.65 kg/Mg (1.3 lb/ton) of glass for gas-fired furnaces or 0.75 kg/Mg (1.5 lb/ton) of glass for oil-fired furnaces [FL]. For glass container furnaces, the standard is 1.0 g/2.0 Kg (1.0 lb/ton) of process material [IN].

The most stringent state opacity standard is 0 percent [FL, MD].

NSPS Subpart CC applies to glass melting furnaces that are designed to produce more than 4,550 kg/day (5 ton/day) of glass that commenced construction or modification after June 15, 1979. The standards are summarized on Table 4-2.

Figure 4-4 presents available total PM test data for controlled glass furnaces (Fitzpatrick, *et al*, 1991; OAQPS, 1980).

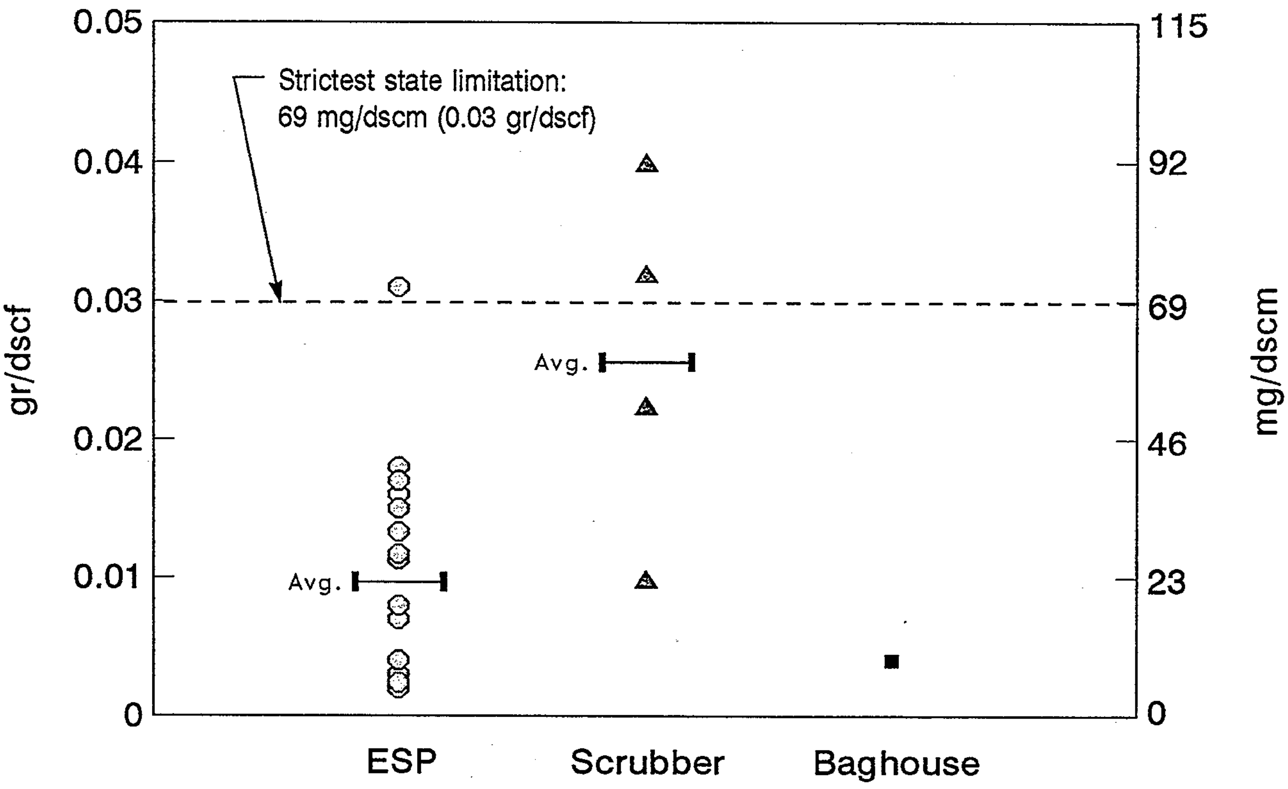
GRAIN MILLING OPERATIONS

Regulations for 45 states (Alaska, Nevada, New Hampshire, West Virginia and Wyoming were not included) were reviewed to determine the strictest standards for grain milling operations. Marine grain terminals are discussed in a later subsection.

TABLE 4-2. SUMMARY OF NSPS SUBPART CC TOTAL PM EMISSIONS LIMITATIONS FOR GLASS MELTING FURNACES IN g/kg (lb/ton) OF PRODUCT

Industry segment	Gaseous fuel-fired	Liquid fuel-fired	Furnaces w/modified processes[a]
Container Glass	0.1 (0.2)	0.13 (0.26)	0.5 (1.0)
Pressed and blown glass			
a) borosilicate recipes	0.5 (1.0)	0.65 (1.30)	1.0 (2.0)
b) soda-lime and lead recipes	0.1 (0.2)	0.13 (0.26)	0.5 (1.0)
c) other than borosilicate, soda-lime and lead recipes	0.25 (0.5)	0.325 (0.65)	- -
Wool fiberglass	0.25 (0.50)	0.325 (0.65)	0.5 (1.0)
Flat glass	0.225 (0.45)	0.225 (0.45)	0.5 (1.0)

[a]Modified processes are any technique that is designed to minimize emissions without add-on air pollution controls.



	ESP	Scrubber	Baghouse
Number of tests	16	4	1
Number of facilities	12	3	1
Maximum, mg/dscm (gr/dscf)	70.9 (0.031)	91.5 (0.040)	9.2 (0.004)
Minimum, mg/dscm (gr/dscf)	4.6 (0.002)	22.9 (0.010)	9.2 (0.004)
Average, mg/dscm (gr/dscf)	25.2 (0.011)	59.5 (0.026)	9.2 (0.004)

Figure 4-4. Examples of total PM emissions test data for glass furnaces.

The strictest state total PM emission standards are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - Varies by production rate; refer to Figure 4-1. However, Curve 1 of this figure does not apply.

- o Production-based rate - For rice mills: 0.75 kg/Mg (1.5 lb/ton) [AR].

- o Other - Discharge gases from grain-drying installations must pass through a 707 μm (24 mesh) screen or equivalent.

The most stringent state opacity standard is 0 percent [FL, MD].

Total PM emissions test data from two grain milling operations equipped with baghouses show concentrations of 10.3 mg/dscm (0.0045 gr/dscf) and 15.3 mg/dscm (0.0067 gr/dscf) (Fitzpatrick *et al*, 1991; Shannon, 1974).

GYPSUM PRODUCT MANUFACTURING AND PROCESSING PLANTS

State regulations for all states except Alabama, Hawaii, Maine, Montana, North Dakota and South Dakota were reviewed to determine the strictest state emission limitations for gypsum operations. NSPS Subpart OOO (nonmetallic mineral processing plants) applies to this source category; a discussion of Subpart OOO appears under the Nonmetallic Mineral Plants subsection.

The most stringent state total PM emission limitations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD, and NY for production rates greater than 45 Mg/hr (50 ton/hr)]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - Refer to Figure 4-1; the allowable emission rate varies by production rate.

The most stringent state opacity standard is 0 percent [MD].

Examples of total PM test data for varies gypsum operations are summarized below (Fitzpatrick, *et al*, 1991):

Operation	Control device	mg/dscm	(gr/dscf)
Calcining	Baghouse	1.4	(0.0006)
		53.8	(0.0235)
		135	(0.059)
Rock dryer	Baghouse	48.5	(0.0212)
	Cyclone	10.1	(0.0044)
	Cyclone/baghouse	8.9	(0.0039)
Wallboard, sawing	Baghouse	10.5	(0.0046)
		23.8	(0.0104)

INCINERATORS

State regulations for medical waste, agricultural waste, and municipal waste incinerators were reviewed for all fifty states. There is also a NSPS for incinerators.

The most stringent total PM state regulations for medical waste incinerators are as follows:

- Concentration - 34 mg/dscm (0.015 gr/dscf) corrected to seven percent oxygen for facilities accepting waste that was generated off-site [NY]. Several other states have a similarly strict standard, however, the standards go into effect at varying production rates [CO, KY, NM].

- Emission rate - For units greater than or equal to 45 kg/hr (100 lb/hr) and less than 907 kg/hr (2,000 lb/hr) the most stringent limitation is 0.05 kg/100 kg charged (0.10 lb/100 lb charged) [OH]. For units greater than 907 kg/hr (2,000 lb/hr), the emission limit is calculated using the following equation: $E = 40.7x10^{-5}C$ where E is the allowable rate (lb/hr) and C is the dry charge rate (lb/hr).

For municipal waste incinerators the most stringent total PM emission limitation expressed as a concentration is 23 mg/dscm (0.010 gr/dscf) at seven percent oxygen [NY]. The most stringent emission rate limitation is the same as the rates described above under medical waste.

The most stringent total PM concentration limit for agricultural waste incineration is 23 mg/dscm (0.010 gr/dscf) at seven percent oxygen for private solid waste disposal [NY]. There are other states have emission limitations for incineration of specific agricultural wastes, such as wood, peanut and cotton ginning wastes [AL] or manure [MI].

The most stringent state VE limit is zero percent [MD].

NSPS Subparts E and Ea apply to incinerators. Subpart E applies to incinerators with a capacity of more than 45 Mg/day (50 ton/day) that commenced construction or modification after August 17, 1971. The particulate standard for Subpart E is 180 mg/dscm (0.08 gr/dscf) corrected to 12 percent carbon dioxide. Subpart Ea applies to municipal waste combustors with a capacity of greater than 225 Mg/day (250 ton/day) that commenced construction or modification after December 20, 1989. The total PM limitation is 34 mg/dscm (0.015 gr/dscf) corrected to seven percent oxygen. VE cannot exceed 10 percent opacity for Subpart Ea sources.

Examples of total PM test data from medical waste incinerators include data from one facility with a baghouse and a concentration of 2.3 mg/dscm (0.001 gr/dscf) and two facilities with wet scrubbers with concentrations of 46 and 92 mg/dscm (0.020 and 0.040 gr/dscf) (Radian, 1988). Examples of total PM data from municipal waste incinerators are summarized below (Fitzpatrick *et al*, 1991; Helfand, 1979; OAQPS, 1989):

	ESP	Fabric filter
Number of facilities	34	6
Maximum, mg/dscm (gr/dscf)	92 (0.04)	73.2 (0.032)
Minimum, mg/dscm (gr/dscf)	4.6 (0.002)	9.2 (0.004)
Average, mg/dscf (gr/dscf)	31 (0.0137)	34 (0.0148)

IRON AND STEEL FACILITIES

The stack test data presented in this section is from the Listing of Iron and Steel Stack Test Reports (Fitzpatrick, 1986) and the Iron and Steel Stack Test Library (JACA, 1991) that is associated with this listing. The library contains approximately 800 stack test reports or summaries of reports and has been compiled under various EPA contracts over the past 12 years.

Argon Oxygen Decarburization and Electric Arc Furnaces

Emission limitations from 35 states for electric arc furnaces (EAF) and argon oxygen decarburization (AOD) vessels were reviewed. There are also applicable NSPSs (Subparts AA and AAa) emission limitations for this source category.

The following is a summary of the most stringent state total PM emissions limitations for EAFs:

- o Concentration - 12 mg/dscm (0.0052 gr/dscf) [CO, DE, NY]

- o Emission rate - The strictest limitation depends on the production rate and is determined by reviewing Figure 4-1 or the following equation: $A = 0.76(40W)^{0.42}$; where A is the allowable rate (lb/hr) and W is the production rate (ton/hr) [PA].

The most stringent state VE limitations for EAFs are as follows:

- o Fugitive emissions - no fugitive emissions.

- o Stack emissions - Two states have similarly stringent limitations. The limitations of the first state are: no VE greater than or equal to 20 percent except for an aggregate of not more than 3 min/hr of VE that are not greater than or equal to 60 percent opacity [PA]. The limitations of the second state are: no VE greater than or equal to 20 percent except for no more than 5 min/hr of VE that are not greater than or equal to 40 percent [CT].

The most stringent state total PM emission limitations for AOD vessels are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf)[FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - The emission limit depends on the production rate as is determined by one of the curves in Figure 4-1 or the following equation: $A = 0.76 (40W)^{0.42}$; where A is the allowable rate (lb/hr) and W is production rate (ton/hr) [PA].

The most stringent state opacity standard is zero percent unless hoods and controls are in place [PA]. Another state allows five percent (6-minute average)[FL].

NSPS Subpart AA applies to EAFs and associated dust-handling equipment that commenced construction, modification or reconstruction after October 21, 1974 but before August 17, 1983. In these cases, total PM emissions from the control device stack are limited to 12 mg/dscm (0.0052 gr/dscf) and an opacity of less than three percent (6-minute average). Visible emissions from the shop that are due solely to the operation of the EAF vessels cannot exhibit greater than or equal to six percent opacity (6-minute average) except that VE less than 20 percent (6-minute average) may occur during charging periods and VE less than 40 percent (6-minute average) may occur during tapping periods. Opacity from dust-handling equipment is limited to less than 10 percent (6-minute average) opacity.

NSPS Subpart AAa applies to EAFs and AODs that were constructed or modified after August 7, 1983. Total PM emissions from an EAF or AOD vessels cannot exceed 12 mg/dscm (0.0052 gr/dscf). VE from a control device stack cannot equal or exceed 3 percent opacity. VE from a shop from EAF or AOD operations cannot exhibit 6 percent opacity or greater.

Figure 4-5 depicts available total PM test data for EAF control device stacks. There is also one stack test available for tapping and charging emissions controlled by a baghouse. The total PM test results are 0.89 mg/dscm (0.00039 gr/dscf).

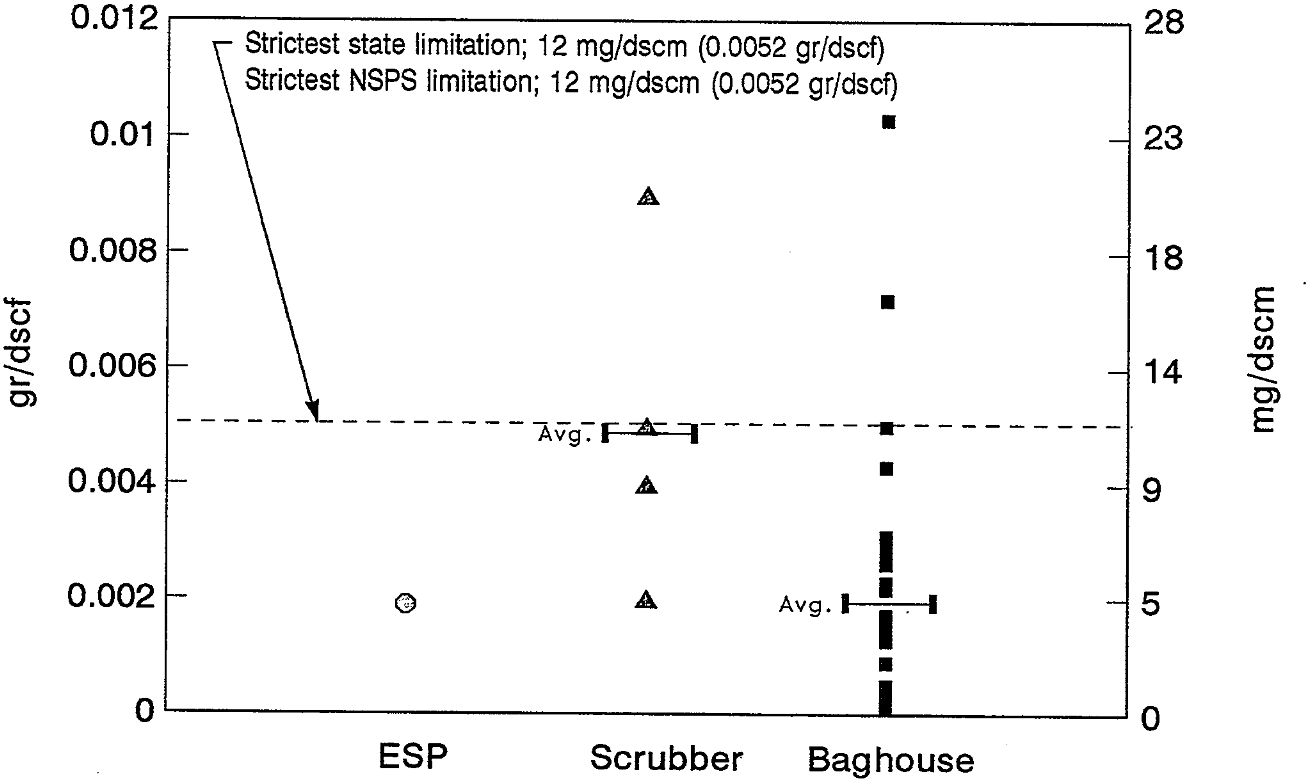
There are two total PM tests available for AOD vessels. One test was conducted at the exhaust at a baghouse and the results are 0.7 mg/dscm (0.0003 gr/dscf). The second test was conducted at the exhaust of a scrubber and the concentration is 27 mg/dscm (0.0118 gr/dscf).

Sinter Plants

To determine the most stringent state regulations for sinter plants, regulations were reviewed for the following states: Alabama, Colorado, Indiana, Illinois, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, Texas, Utah, and West Virginia.

The most stringent total PM emission regulations for sinter plant windboxes are:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [AL, CO, MD, WV].



	ESP	Scrubber	Baghouse
Number of tests	1	4	24
Number of facilities	1	4	19
Maximum, mg/dscm (gr/dscf)	4.4 (0.0019)	20.6 (0.009)	23.6 (0.0103)
Minimum, (mg/dscm) (gr/dscf)	4.4 (0.0019)	4.6 (0.002)	0.05 (0.00002)
Average, (mg/dscm) (gr/dscf)	4.4 (0.0019)	11.5 (0.005)	5.0 (0.0022)

Figure 4-5. Examples of total PM emissions test data for primary emission control systems at electric arc furnaces at iron and steel facilities.

- Emission rate - The most stringent limit is calculated by the following equation: $A = 0.76(20W)^{0.42}$; where A is the allowable rate (lb/hr) and W is production rate (ton/hr)[PA].

The most stringent total PM limitations for other sinter plant operations are as follows:

- Sinter discharge end - 23 mg/dscm (0.01 gr/dscf)[CO].

- Sinter breaker - As calculated by the following equation: $E = 2.54P^{0.534}$; where E is the allowable rate (lb/hr) and P is production rate up to 408 Mg/hr (450 ton/hr)[IL].

- Hot and cold screens - 69 mg/dscm (0.03 gr/dscf)[IL, MD].

- Sinter cooler - 46 mg/dscm (0.02 gr/dscf)[WV].

The most stringent VE limitations are as follows:

- Fugitive - no fugitive emissions [PA].

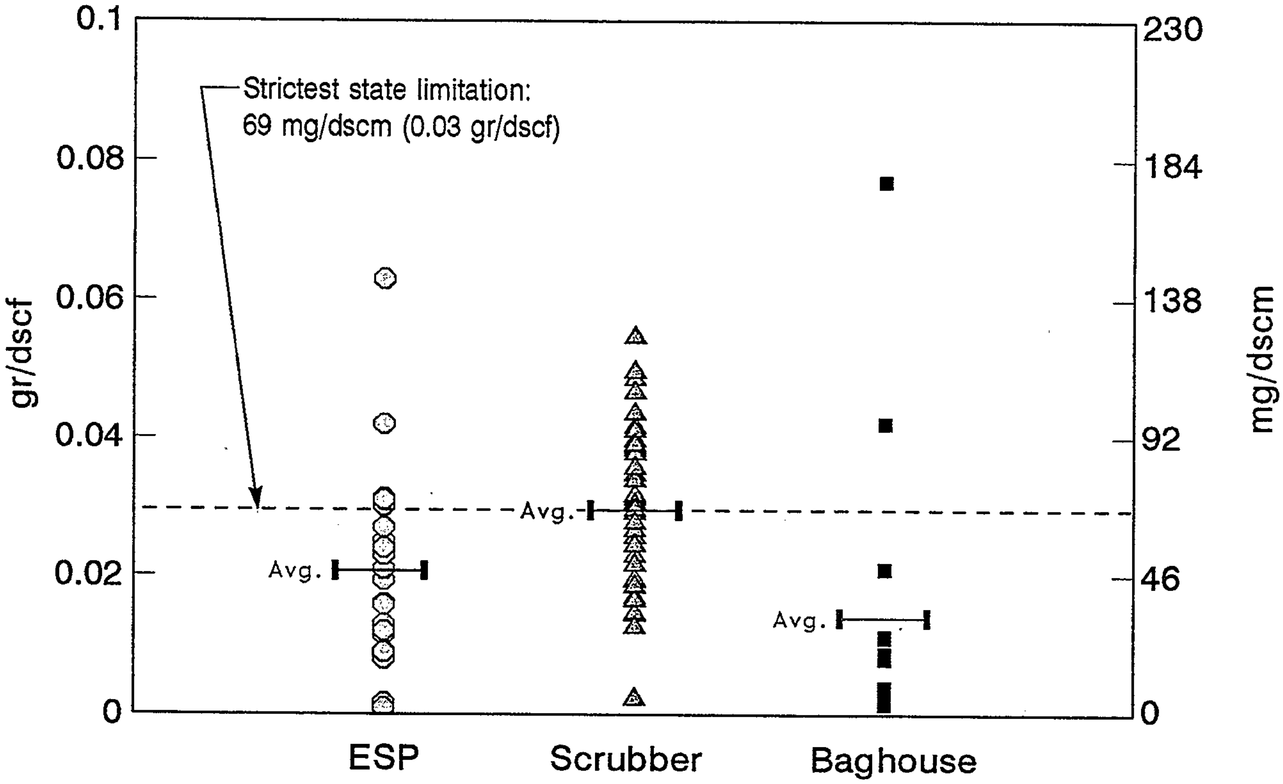
- Stack emissions - No VE greater than 10 percent [MD].

Examples of total PM emissions data for sinter plant windboxes is summarized on Figure 4-6. Examples of total PM test data for other sinter plant operations are summarized on Table 4-3.

<u>Coke Batteries</u>

State regulations were reviewed for by-product coke batteries for the following states: Alabama, Colorado, Indiana, Illinois, Kentucky, Maryland, Michigan, Missouri, New York, Ohio, Pennsylvania, Texas, Utah, Wisconsin and West Virginia. Coke pushing and coke underfire or combustion stack operations were included in the review. There are other emission sources at coke plants, such as door leaks, battery topside leaks, and quenching, however, there are generally no mass emission standards for these emission sources. (Opacity standards are generally specified for door leaks and battery topside leaks; water quality of the quench water may be specified for coke quenching.)

The most stringent total PM emission limitations for coke pushing are summarized as follows:



	ESP	Scrubber	Baghouse
Number of tests	26	46	13
Number of facilities	7	14	6
Maximum, mg/dscm (gr/dscf)	144.2 (0.063)	126.1 (0.0551)	176.2 (0.077)
Minimum, mg/dscm (gr/dscf)	18.3 (0.008)	6.2 (0.0027)	3.4 (0.0015)
Average, mg/dscm (gr/dscf)	50.3 (0.022)	68.6 (0.030)	36.8 (0.0161)

Figure 4-6. Examples of total PM emissions test data for sinter plant windboxes at iron and steel facilities.

TABLE 4-3. SUMMARY OF EXAMPLE TOTAL PM EMISSIONS TEST DATA FOR SINTER PLANT OPERATIONS (EXCLUDING SINTER PLANT WINDBOXES)[a]
mg/dscm (gr/dscf)

Sinter operation: control device	No. of tests	No. of facilities	Maximum	Minimum	Average
Raw materials transfer/handling:					
Scrubber	3	2	23 (0.01)	2 (0.0008)	10 (0.0044)
Baghouse	2	2	101 (0.044)	21 (0.009)	59 (0.026)
Sinter discharge end:					
Scrubber	3	2	76 (0.033)	37 (0.016)	55 (0.024)
Baghouse	8	7	101 (0.044)	5 (0.0023)	47 (0.0205)
Rotoclone	10	2	275 (0.12)	5 (0.002)	46 (0.0203)
Sinter breaker:					
Scrubber	3	2	203 (0.0888)	32 (0.0138)	103 (0.0452)
Baghouse	2	2	96 (0.0421)	14 (0.006)	55 (0.024)
Rotoclone	2	1	18 (0.008)	7 (0.003)	13 (0.0055)
Hot screening:					
Scrubber	5	3	203 (0.0888)	2 (0.0008)	65 (0.0282)
Baghouse	1	1	14 (0.006)	14 (0.006)	14 (0.006)
Rotoclone	9	3	46 (0.02)	7 (0.003)	23 (0.010)
Sinter cooler:					
Scrubber	1	1	34 (0.015)	34 (0.015)	34 (0.015)
Cyclone	1	1	14 (0.006)	14 (0.006)	14 (0.006)
Cold screening:					
Baghouse	1	1	7 (0.003)	7 (0.003)	7 (0.003)
Rotoclone	1	1	27 (0.012)	27 (0.012)	27 (0.012)

[a]Some control devices control emissions from multiple sources; test data may be listed under more than one operation.

- Concentration - 69 mg/dscm (0.03 gr/dscf)[MD].

- Emission rate - Emission rate varies by production rate and is determined by one of the following equations: 1) $A = 0.76(1W)^{0.42}$; where A is the allowable rate (lb/hr) and W is amount of coke pushed (ton/hr)[PA] or 2) $E = C^{0.09}$, where E the is allowable rate (lb/push) and C is coal charge rate (ton/oven)[WV].

- Production-based rate - 0.015 kg/Mg (0.03 lb/ton) of coke [CO, KY].

The most stringent opacity limit for coke pushing operations states that fugitive emissions from a coke pushing air cleaning device shall not exceed 20 percent opacity (any individual reading) during pushing unless the emissions are of minor significance as determined by the state agency and 10 percent during the transport of hot coke in the open atmosphere [PA].

Figure 4-7 illustrates examples of total PM emissions test data on coke pushing control systems.

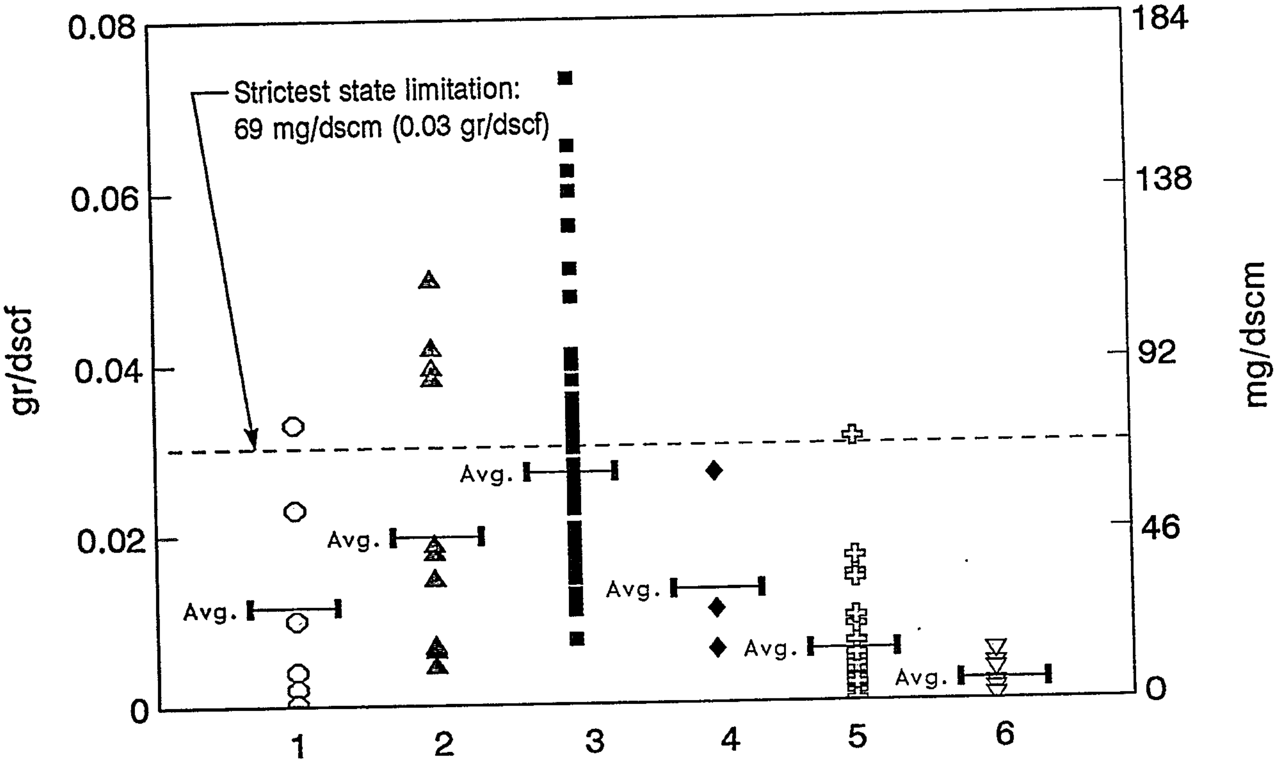
The most stringent state total PM emission limitations on coke oven underfire or combustion stacks is 57 mg/dscm (0.025 gr/dscf)[WV]. The most stringent VE limitation for combustion stacks is zero percent [MD].

Examples of total PM emissions test data from controlled combustion stacks are summarized below:

	ESP	Baghouse
Number of tests	14	10
Number of facilities	8	1
Maximum, mg/dscm (gr/dscf)	87 (0.038)	119 (0.052)
Minimum, mg/dscm (gr/dscf)	9 (0.004)	2 (0.001)
Average, mg/dscm (gr/dscf)	37 (0.016)	41 (0.018)

<u>Slag Handling</u>

Slag handling is a fugitive dust emission source. Fugitive dust regulations were reviewed for 35 states (the states with iron or steel making furnaces). The most stringent state limitation stipulates that there shall be no fugitive emissions



System configurations as follows:

1 - Shed with ESP
2 - Hood with land-based scrubber
3 - Mobile car with scrubber
4 - Shed with scrubber
5 - Hood with land-based baghouse
6 - Shed with baghouse

System configuration	1	2	3	4	5	6
Number of tests	6	12	51	3	18	6
Number of facilities	3	6	19	3	13	4
Maximum mg/dscm (gr/dscf)	75.5 (0.033)	114.4 (0.050)	167.3 (0.0731)	61.8 (0.027)	70.7 (0.0309)	12.8 (0.0056)
Minimum mg/dscm (gr/dscf)	0.5 (0.0002)	11.0 (0.0048)	17.4 (0.0076)	14.4 (0.0063)	0.5 (0.0002)	0.7 (0.0003)
Average mg/dscm (gr/dscf)	27.5 (0.0120)	50.1 (0.0219)	65.4 (0.0286)	33.9 (0.0148)	16.9 (0.0074)	6.2 (0.0027)

Figure 4-7. Examples of total PM emissions test data for coke pushing at iron and steel facilities.

[PA]. Many states specify reasonable precautions or measures shall be taken to reduce fugitive dust.

Blast Furnaces

State regulations for Alabama, Colorado, Illinois, Indiana, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, Texas, Utah, and West Virginia were reviewed to determine the most stringent mass and opacity limitations for blast furnace casthouses. The most stringent total PM emissions limitations are as follows:

- Concentration - 23 mg/dscm (0.01 gr/dscf) from air pollution control device stacks [KY, MI].
- Emission rate - As determined by the following equation for sources up to 408 Mg/hr (450 ton/hr): $E = 2.54P^{0.534}$; where E is the allowable rate (lb/hr) and P is the production rate (ton/hr).
- Production-based rate - 0.015 kg/Mg (0.03 lb/ton) of hot metal [IN - this emission rate is specific for a particular emission source].

The most stringent VE limitation for fugitive emissions is no fugitive emissions [PA]. The most stringent limitation for VE from the air pollution control device stack is zero percent [MD].

Six examples of total PM emission test data are available from six facilities using baghouses to control blast furnace casthouse emissions. The average results are 17 mg/dscm (0.0075 gr/dscf) with a range of 0.7 to 66 mg/dscm (0.0003 to 0.0287 gr/dscf). Another common control system that is employed at blast furnace casthouses is suppression technology. This type of control system uses technology to suppress the formation of the pollutants such as unevacuated hoods or covers and flame or nitrogen gas blankets. There are no exhaust stacks as there are with traditional air pollution control devices.

Basic Oxygen Furnaces

Emission limitations for basic oxygen furnaces (BOF) were reviewed for the following states: Alabama, Colorado, Illinois, Indiana, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, and West Virginia. There is also an applicable NSPS limitation (Subparts N and Na).

The most stringent state total PM emission limitations for BOF vessels are as follows:

- Concentration - 50 mg/dscm (0.0220 gr/dscf) during the oxygen blow and 23 mg/dscm (0.0100 gr/dscf) during scrap charging, hot metal transfer, tapping, and slagging (secondary emissions).

- Emission rate - One state specifies 2.27 kg/hr/furnace (5 lb/hr/furnace) as an emission rate [IN, specific to an individual furnace]. For emission rate limitations that vary by production rate the equation that yields the strictest emission limitations is: $A = 0.76 (40W)^{0.42}$; where A is the allowable emission rate (lb/hr) and W is the production rate (ton/hr).

- Production-based rate - 0.045 kg/Mg (0.09 lb/ton) steel for stack emissions and 0.1 kg/Mg (0.2 lb/ton) steel for the roof monitor [IN, specific to an individual facility].

The most stringent state VE limitation for emissions from the roof monitor is zero percent [PA]. The most stringent state limitation for stack VE is zero percent [MD].

NSPS Subparts N and Na apply to BOFs. Subpart N applies to BOFs that commenced construction or modification after June 11, 1973. This subpart states that atmospheric particulate emissions shall not exceed 50 mg/dscm (0.022 gr/dscf). VE from a control device cannot be greater than or equal to 10 percent except that an opacity greater than 10 percent but less than 20 percent may occur once per steel production cycle. For BOFs constructed or modified after January 20, 1983, total PM emissions from vessels that use open hooding as the method of controlling primary emissions are limited to 50 mg/dscm (0.022 gr/dscf) measured during the oxygen blow. Emissions from a control device not used solely for the collection of secondary emissions shall not be greater than or equal to 10 percent opacity except that an opacity greater than 10 percent and less than 20 percent may occur once per steel production cycle. Vessels that use closed hooding as the method for controlling total PM emissions are limited to 68 mg/dscm (0.030 gr/dscf) as measured during the oxygen below. The VE limit for closed hooding vessels is the same as the limit for open hooding vessels.

Subpart Na applies to secondary emissions from BOFs that were constructed or modified after January 20, 1983. Particulate emissions from a BOF shop roof monitor cannot be greater than or equal to 10 percent opacity during the steel production cycle of any top-blown vessel or during hot metal transfer or skimming operations for any bottom-blown BOF except that an opacity greater than 10 percent but less than 20 percent may occur once per steel production cycle. Control devices that are used only for the collection of secondary emissions from a top-blown vessel or from hot metal transfer or skimming for a bottom-blown or top-blown vessel total PM emissions cannot exceed 23 mg/dscm (0.010 gr/dscf) and exhibit more than five percent opacity.

Table 4-4 presents examples of total PM test data from BOF vessels.

Scarfing

Regulations for Alabama, Colorado, Illinois, Indiana, Maryland, Michigan, Missouri, New York, Ohio, Pennsylvania, Texas and West Virginia were reviewed to determine the most stringent mass and opacity limitations for automatic scarfing operations.

The most stringent state total PM emission limitations are as follows:

- o Concentration - 46 mg/dscm (0.02 gr/dscf) during scarfing [IN, for a specific facility]. 69 mg/dscm (0.03 gr/dscf) is the most stringent limitation that is not specific to an individual facility [IL, MD, MI, WV].

- o Emission rate - Calculated using the following equation: $A = 0.76(20W)^{0.42}$; where A is the allowable rate (lb/hr) and W is the production rate (ton/hr) [PA].

The most stringent opacity limit is 0 percent [MD].

Examples of total PM emissions test data are summarized below.

	ESP	Scrubber
Number of tests	22	5
Number of facilities	13	4
Maximum, mg/dscf (gr/dscf)	110 (0.048)	108 (0.047)
Minimum, mg/dscm (gr/dscf)	0.7 (0.0003)	11 (0.0046)
Average, mg/dscm (gr/dscf)	17 (0.0074)	69 (0.0301)

TABLE 4-4. SUMMARY OF EXAMPLE TOTAL PM EMISSIONS TEST DATA FOR BOF VESSELS
mg/dscm (gr/dscf)

Type of vessel[a]: control device[b]	No. of tests	No. of facilities	Maximum	Minimum	Average
Bottom-blown; partial hood:					
Scrubber	12	3	82 (0.036)	12 (0.0051)	38 (0.0166)
Top-blown; full hood:					
ESP	58	16	208 (0.091)	7 (0.0031)	34 (0.015)
Scrubber	27	12	160 (0.07)	9 (0.004)	46 (0.020)
Top-blown; partial hood:					
Scrubber	13	6	44 (0.0192)	5 (0.0023)	19 (0.0083)
All types; secondary emissions[c] control:					
ESP	6	3	14 (0.0063)	4 (0.0017)	9 (0.0037)
Scrubber	1	1	21 (0.009)	21 (0.009)	21 (0.009)
Baghouse	5	3	44 (0.019)	0.1 (0.00003)	13 (0.0058)

[a]BOF vessels classified by oxygen blowing mechanism (either top-blown or bottom-blown) and by the type of combustion hood (either full or partial).

[b]Control devices are controlling primary emissions (emissions during the oxygen blow) unless otherwise indicated.

[c]Secondary emissions include vessel charging, tapping, slagging, and metal transfers. Tests shown above may include one or more of these operations.

Hot Metal Reladling

Emission limitations for hot metal reladling were reviewed for the following states: Alabama, Colorado, Illinois, Indiana, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, and West Virginia. The most stringent total PM emissions limitations are as follows:

- o Concentration - 23 mg/dscm (0.0100 gr/dscf) [CO].
- o Emission rate - Calculated using the following equation: $E = 17.31P^{0.16}$ for production rates greater than 27 Mg/hr (30 ton/hr); where E is the allowable rate (lb/hr) and P is the production rate (ton/hr).

The most stringent limitation for VE from the stack is 0 percent opacity [MD].

Examples of total PM emissions test data from hot metal reladling operations are:

	ESP	Baghouse
Number of tests	1	10
Number of facilities	1	7
Maximum, mg/dscm (gr/dscf)	6 (0.0024)	39 (0.0172)
Minimum, mg/dscm (gr/dscf)	6 (0.0024)	1 (0.0003)
Average, mg/dscm (gr/dscf)	6 (0.0024)	12 (0.0054)

LIME PLANTS

State regulations for rotary lime kilns at lime plants were reviewed for all states except Colorado, Delaware, Hawaii, Maine, Montana, Nebraska, North Dakota, and Wyoming. There is also an applicable NSPS emission limitation for this source category. The crushing, screening and material handling operations that may be associated with rotary lime kilns are discussing under the Nonmetallic Mineral Plants subsection.

The most stringent state total PM emission limitations for lime kilns are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD, NY - for kilns greater than 45 Mg/hr (50 ton/hr)].

Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - The strictest limitation varies by production rate; see Figure 4-1.

- o Production-based rate - 0.15 kg/Mg (0.30 lb/ton) of feed [NM].

The most stringent state opacity limit is zero percent [MD].

NSPS Subpart HH applies to rotary lime kilns at lime manufacturing plants that were constructed or modified after May 3, 1977. Total PM shall not exceed 0.30 kg/Mg (0.60 lb/ton) of stone feed. Opacity from a dry emission control device cannot exceed 15 percent.

Figure 4-8 summarizes examples of total PM emissions data for lime kilns (includes data for several lime kilns at pulp mills) (Fitzpatrick, *et al*, 1991; OAQPS, 1977; OAQPS, 1976; OAQPS, 1977; Kinsey, 1986).

LUMBER MILLS

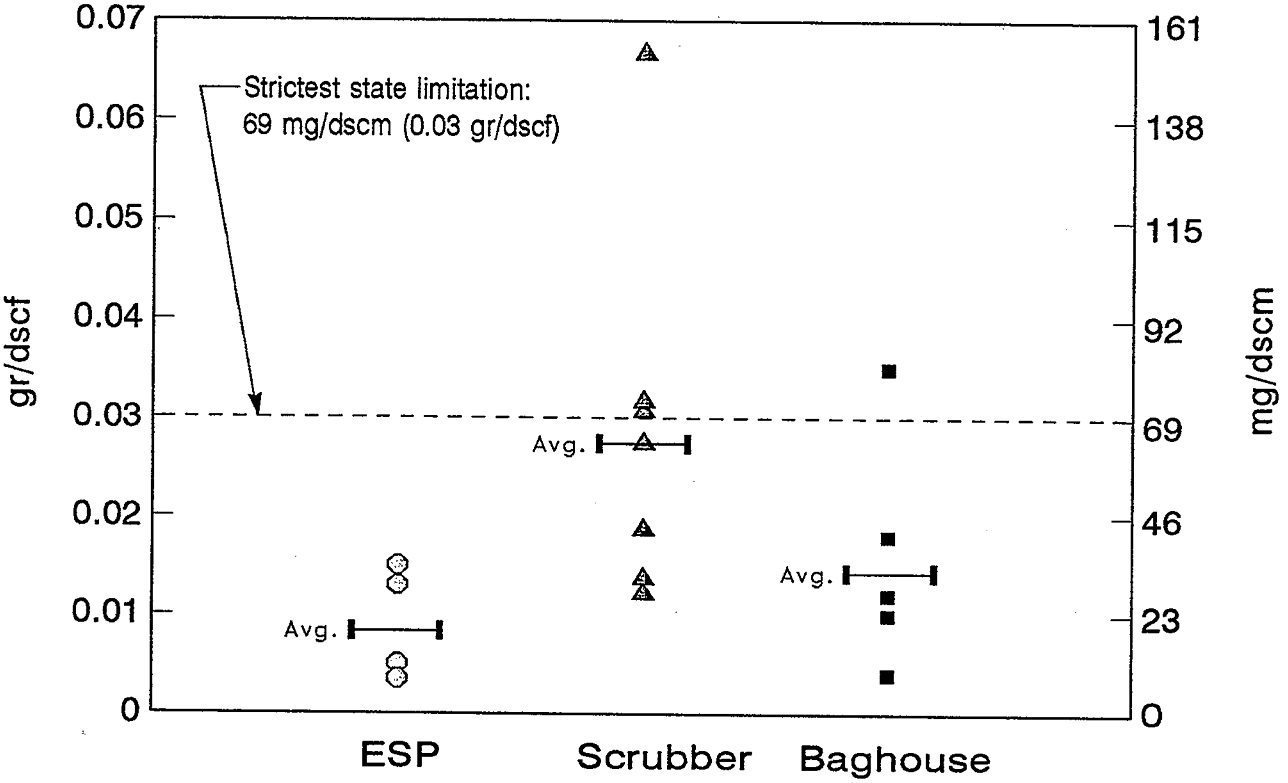
State regulations for all 50 states were reviewed to determine the most stringent total PM limitations for planning, shaving and combustion of wood waste at lumber mills.

The most stringent total PM emission limitations for planning and shaving operations that are exhausted through a stack are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [MD, FL]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - Varies by production rate; see Figure 4-1.

Emission limitations for combustion of wood waste in boilers are presented in the Boilers portion of this Section. Combustion of wood in wood waste burners is limited to 459 mg/dscm (0.2 gr/dscf) corrected to 12 percent carbon dioxide [AZ, IL].



	ESP	Scrubber	Baghouse
Number of tests	4	8	5
Number of facilities	4	6	5
Maximum, mg/dscm (gr/dscf)	34.3 (0.015)	153.3 (0.067)	80.1 (0.035)
Minimum, mg/dscm (gr/dscf)	8.0 (0.0035)	28.6 (0.0125)	9.2 (0.004)
Average, mg/dscm (gr/dscf)	20.8 (0.0091)	66.1 (0.0289)	36.6 (0.016)

Figure 4-8. Examples of total PM emissions test data for lime plants.

Operational and monitoring requirement on wood waste burners are imposed in some states [MT, OR, WA, WY]. Several states also have policies to encourage means, other than incineration, of wood waste disposal [MT, OR].

MARINE GRAIN TERMINALS

Regulations for 45 states (Alaska, Nevada, New Hampshire, West Virginia and Wyoming were not included) were reviewed to determine the most stringent limitations for shipping (load-out), receiving (unloading) and other grain handling operations. There is an applicable NSPS for this source category.

The most stringent total PM emissions regulations are summarized as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) if a control device has been installed [FL]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - Varies by production rate; see Figure 4-1. Pennsylvania has emission rates that vary by production rate specifically for grain elevators on grain screening/cleaning, however, the curves produce less stringent limits than those depicted on Figure 4-1.

- Other - Particulate matter cannot be larger than that which would pass through a 707 μm (24 mesh) screen.

The most stringent opacity standard limits VE to zero percent except 10 percent when loading to ship via a conveyor and the hatch is moved [FL].

NSPS Subpart DD applies to grain terminal elevators that were constructed or modified after August 3, 1978. Specifically this Subpart applies to barge and ship loading and unloading stations and other grain handling operations. Fugitive emissions from barge or ship loading stations cannot exhibit greater than 20 percent opacity. Fugitive emissions from any grain handling operations cannot exhibit greater than zero percent opacity. There are also operating requirements specified for ship unloading stations.

Total PM test data from grain loading from a barge equipped with a filter showed a concentration of 60 mg/dscm (0.0261 gr/dscf) (Fitzpatrick, *et al*, 1991).

METALLIC MINERAL PROCESSING PLANTS

State regulations were reviewed for all 46 states (Alaska, Delaware, North Dakota and South Dakota were not included) to determine the most stringent mass and opacity limitations for ore concentrators at nonferrous smelting facilities. There is an applicable NSPS for this source category.

The most stringent total PM emission regulations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - Varies by production rate; refer to Figure 4-1.

The most stringent opacity limitation is zero percent [MD]. Fugitive emissions are limited to none [PA].

NSPS Subpart LL applies to metallic mineral processing plants that were installed or modified after August 24, 1982. Total PM emissions are limited to 50 mg/dscm (0.0218 gr/dscf). Opacity cannot exceed seven percent unless a wet scrubber is used as the control device. Process fugitive emissions cannot exceed 10 percent opacity.

Examples of total PM emissions test data are summarized on Table 4-5 (Fitzpatrick, *et al*, 1991).

NONMETALLIC MINERAL PLANTS

Mass and opacity regulations for all fifty states were reviewed to determine the most stringent limitations for conveyors and other material handling operations, screens, quarrying, and rock crushers at nonmetallic mineral plants. There is also an applicable NSPS for this source category.

The most stringent state total PM emission limitations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, IN, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an

TABLE 4-5. SUMMARY OF EXAMPLE TOTAL PM EMISSIONS TEST DATA FOR NONFERROUS ORE CONCENTRATORS

mg/dscm (gr/dscf)

Process operation: control device	No. of tests	No. of facilities	Maximum	Minimum	Average
Copper, truck loadout:					
Baghouse	3	2	36 (0.0156)	0.2 (0.0001)	18.4 (0.008)
Copper, primary crusher:					
Baghouse	1	1	12.9 (0.0056)	12.9 (0.0056)	12.9 (0.0056)
Fabric filter and chemical wet suppression	1	1	0.2 (0.0001)	0.2 (0.0001)	0.2 (0.0001)
Not specified	1	1	24.4 (0.0106)	24.4 (0.0106)	24.4 (0.0106)
Copper, secondary crusher:					
Not specified	1	1	41.1 (0.0179)	41.1 (0.0179)	41.1 (0.0179)
Molybdenum, primary crusher:					
Venturi scrubber and wet suppression	1	1	11.9 (0.0052)	11.9 (0.0052)	11.9 (0.0052)
Molybdenum, pebble screening and milling:					
Venturi scrubber	1	1	15.6 (0.0068)	15.6 (0.0068)	15.6 (0.0068)
Uranium, primary crusher:					
Centrifugal scrubber	1	1	84.1 (0.0366)	84.1 (0.0366)	84.1 (0.0366)

(Continued)

TABLE 4-5. (CONTINUED)

Process operation: control device	No. of tests	No. of facilities	Maximum	Minimum	Average
Uranium, ore bins:					
Centrifugal scrubber	1	1	53.5 (0.0233)	53.5 (0.0233)	53.5 (0.0233)
Zinc, ore processing:					
Baghouse	2	1	131.4 (0.0572)	88.4 (0.0385)	110.0 (0.0479)
Ore bins:					
Baghouse	2	2	6.9 (0.003)	0.2 (0.0001)	3.7 (0.0016)
Unloading:					
Scrubber	1	1	39 (0.017)	39 (0.017)	39 (0.017)

upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - varies by production rate; refer to Figure 4-1.

The most stringent state opacity limitation is 0 percent for stacks [FL, MD] and fugitive sources [PA].

NSPS Subpart OOO applies to nonmetallic mineral processing plants that were installed or modified after August 31, 1983. Stack total PM emissions can not contain more than 50 mg/dscm (0.0218 gr/dscf) of particulate matter or exhibit greater than 7 percent opacity (unless emissions are controlled by a wet scrubber). Fugitive emissions from affected sources (except crushers which do not use a capture system, truck dumping, and sources enclosed by a building) are limited to 10 percent opacity. Fugitive emissions from crushers which do not use a capture system can not exceed 15 percent opacity. Sources that are enclosed by a building can meet the VE requirements of the individual sources or the building must not exhibit any visible fugitive emissions.

Examples of total PM emissions test data are summarized below (Fitzpatrick, *et al*, 1991):

Operation	Control	mg/dscm	(gr/dscf)
Kaolin, impact mill	Baghouse	17 37	(0.0073) (0.0160)
Roller and bowl mill	Cyclones and baghouse	7	(0.003)
Granite, secondary crushing	Wet suppression	1	(0.0003)
Talc, pebble grinding	Baghouse	66	(0.0285)

PAINT MANUFACTURING PLANTS

State regulations for all 50 states were reviewed to determine the most stringent total PM and opacity limitations for paint manufacturing plants. The most stringent mass limitations are summarized as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - The strictest limitation is calculated using the following equation: $A = 0.76(0.05W)^{0.42}$; where A is the allowable rate (lb/hr) and W is the amount of pigment handled (ton/hr).

PETROLEUM REFINERIES

State regulations for all states except Idaho, Maine, New Hampshire, and North Carolina were reviewed to determine the most stringent total PM and opacity limitations for petroleum refineries. There is applicable NSPS for this source category.

The most stringent state total PM emissions limitations are summarized below:

- Concentration - 62.0 mg/dscm (0.0270 gr/dscf) [UT, specific facility]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - For catalytic cracking units, calculated from the following equation $A = 0.76 (40W)^{0.42}$; where A is the allowable rate (lb/hr) and W is liquid feed rate (ton) [PA].

- Production-based rate - For catalytic cracking units, 1.0 kg/1000 kg (1.0 lb/1,000 lb) of coke burnoff with an additional incremental rate of 43 g/MJ (0.10 lb/MMBtu) of heat input attributable to fuel if the gases pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned [AK, KY, MN, NM, NY, WI].

- Other - Recover 99.97 percent of catalyst or total gas-born particulate [IN].

Visible emissions are limited to zero percent opacity [FL, MD].

NSPS Subpart J applies to fluid catalytic unit catalyst regenerators (FCCU) which were installed or modified after June 11, 1973. Total PM in the exhaust gas cannot exceed 1.0 kg/1000 kg (1.0 lb/1000 lb) of coke burn-off in the catalyst regenerator. Opacity cannot be greater than 30 percent except for one six-minute period per hour. If gases from the FCCU pass through an incinerator or waste fuel boiler that burns auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of total PM emissions shall not exceed 43 g/MJ (0.10 lb MMBtu) of heat input attributable to the liquid or solid fossil fuel.

PHOSPHATE FERTILIZER PLANTS

State regulations relative to phosphate fertilizer plants were reviewed for the following states: Alabama, Arizona, Arkansas, Florida, Georgia, Idaho, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Virginia, Wisconsin, and Wyoming. There are also several applicable NSPSs for this source category, however, the emission limitations pertain to fluorides.

The most stringent state total PM emission limitations are as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [MD].
- Emission rate - Calculated using the following equation: $E = 1.10(PW)^{0.25}$; where E is the allowable rate (lb/hr) for operations greater than 4.2 Mg/hr (9,250 lb/hr) and PW is production rate (lb/hr) [ID]. Concentrators at phosphate processing facilities are limited to 6.8 kg/hr (15 lb/hr) in Florida.
- Production-based rate - 0.15 kg/Mg (0.30 lb/ton) at phosphate processing facilities [FL].

Visible emissions are limited to zero percent opacity [MD].

PHOSPHATE ROCK PROCESSING PLANTS

State regulations for Florida, Idaho, Missouri, Montana, Nebraska, North Carolina, Tennessee, Utah and Wyoming were reviewed to determine the most stringent mass and opacity limitations for phosphate rock processing. There is also an applicable NSPS for this source category.

The most stringent total PM emission limitations are as follows:

- Emission rate - Calculated using the following equation for operations greater than 4.2 Mg/hr (9,250 lb/hr): E = $1.10(PW)^{0.25}$; where E (lb/hr) is the allowable rate and PW is production weight (lb/hr) [ID]. Concentrators are limited to 6.8 kg/hr (15 lb/hr) [FL].

- Production-based rate - 0.1 kg/Mg (0.20 lb/ton) for dryers or grinders [FL].

There are several states with similarly strict opacity limits:

- VE cannot exceed 20 percent opacity for not more than an aggregate of 3 min/hr [ID].

- VE cannot exceed 20 percent opacity for not more than 5 min/hr or 20 minutes per 24 hr [IN].

- VE cannot equal or exceed 20 percent opacity (6-minute average) [MT, NE].

NSPS subpart NN applies to phosphate rock plants with a capacity greater than 3.6 Mg/hr (4 ton/hr) that were installed or modified after September 21, 1979. Total PM and opacity limitations are as follows:

	Mass limitation kg/Mg (lb/ton) of rock feed	Opacity limitation, %
Phosphate rock dryer	0.030 (0.06)	10
Phosphate rock calciner processing unbeneficiated rock	0.12 (0.23)	10
Phosphate rock calciner processing beneficiated rock	0.055 (0.11)	10
Phosphate rock grinder	0.006 (0.012)	0
Ground phosphate rock handling and storage system	-	0

Examples of total PM emissions test data are summarized in Table 4-6. (Fitzpatrick, *et al*, 1991; Kinsey, 1986).

TABLE 4-6. SUMMARY OF EXAMPLE
TOTAL PM EMISSIONS TEST DATA FOR PHOSPHATE
ROCK PROCESSING

mg/dscm (gr/dscf)

Process operation: control device	No. of tests	No. of facilities	Maximum	Minimum	Average
Grinders: Baghouse	6	5	21.8 (0.0095)	2.3 (0.001)	8.7 (0.0038)
Dryers: Scrubber and ESP	1	1	18.4 (0.008)	18.4 (0.008)	18.4 (0.008)
Venturi Scrubber	2	1	29.9 (0.013)	20.7 (0.009)	25.3 (0.011)
Calciners: Scrubber	5	2	62.0 (0.027)	0.7 (0.0003)	45.3 (0.0197)

PLYWOOD, PARTICLEBOARD, AND WAFERBOARD PLANTS

Mass and opacity limitations were reviewed for plywood, particleboard and waferboard plants (including veneer dryers) for all 50 states. The most stringent total PM emissions limitations are as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than or equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - Varies by production rate; see Figure 4-1.

- Production-based rate - As listed below:

Plywood and veneer units using fuel with moisture content >20%	3.7 kg/1,000 m^2 (0.75 lb/1,000 ft^2)
Plywood and veneer units using fuel with moisture content <20%	7.3 kg/1,000 m^2 (1.50 lb/1,000 ft^2)
Plywood and veneer units; combustion	0.40 kg/1,000 kg (0.40 lb/1,000 lb steam)
Plywood and veneer, other operations	4.9 kg/1,000 m^2 (1.0 lb/1,000 ft^2)
Particleboard manufacturing truck dumping and storage	Enclose areas or equivalent alternative controls
Particleboard manufacturing, other sources (excluding truck dumping, storage, fuel or refuse burning equipment)	Total all sources: 14.7 kg/1,000 m^2 (3.0 lb/1,000 ft^2)
Hardboard manufacturing, truck dumping and storage	Enclose areas or equivalent alternative controls

Hardboard manufacturing, other sources (excluding truck dumping, storage, fuel or refuse burning equipment).	Total all sources: 4.9 kg/1,000 m^2 (1.0 lb/1,000 ft^2)

The most stringent state visible emission limitation is 0 percent [MD].

PORTLAND CEMENT PLANTS

State regulations were reviewed for all states except North Dakota and Rhode Island to determine the most stringent total PM and opacity limitations for portland cement plants. There is also an applicable NSPS for this source category.

The most stringent state total PM emission limitation for cement kilns are as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - Varies by production rate; refer to Curve 3 [ID] and Curve 4 [MA] on Figure 4-1.

- Production based rate - 0.15 kg/Mg (0.30 lb/ton) of feed [AL, FL, IL, MN, NH, NY, WI].

- Other - 99.7 control efficiency and not greater than 230 mg/dscm (0.1 gr/dscf) [IA] or not greater than 0.873 g/kg (0.327 lb/barrel) [NC].

The most stringent state total PM emission limitations for clinker coolers are as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- Emission rate - Varies by production rate; use Figure 4-1, Curves 3 and 4 [ID, MA] or the following equation:

$A = 0.76(50W)^{0.42}$; where A is the allowable rate (lb/hr) and W is production rate (ton/hr).

The most stringent state total PM emission limitations for other operations at portland cement plants are:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - Varies by production rate; refer to Figure 4-1.

The most stringent opacity limitation is 0 percent [MD]. Fugitive emissions are limited to none [PA].

NSPS Subpart F applies to portland cement plants that were installed or modified after August 17, 1971. Total PM emission in the kiln exhaust gas can not exceed 0.15 kg/Mg (0.30 lb/ton) of feed and opacity cannot be greater than 20 percent. Clinker cooler total PM emissions are limited to 0.050 kg/Mg (0.10 lb/ton) of feed to the kiln and opacity cannot equal or exceed 10 percent. Other emission sources at portland cement plants cannot equal or exceed 10 percent opacity.

Examples of total PM emissions data from portland cement plants are summarized on Table 4-7 (Fitzpatrick, *et al*, 1991; Kinsey, 1987; Engineering-Science, Inc., 1978).

PRIMARY ALUMINUM REDUCTION FACILITIES

State regulations were reviewed for 27 states to determine the strictest total PM and opacity limits for prebaked, vertical stud Soderberg and horizontal stud Soderburg aluminum reduction cells at primary aluminum reduction facilities. There is an applicable NSPS for this source category.

The most stringent state total PM emissions regulations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD, NY].

- o Emission rate - Varies by production rate; see Curves 1 and 2 on Figure 4-1.

TABLE 4-7. SUMMARY OF EXAMPLE TOTAL PM EMISSIONS TEST DATA FOR PORTLAND CEMENT PLANTS

mg/dscm (gr/dscf)

Process operation: control device	No. of tests	No. of facilities	Maximum	Minimum	Average
Cement kiln:					
ESP	10	5	234 (0.102)	12 (0.005)	67 (0.029)
Scrubber	1	1	99 (0.043)	99 (0.043)	99 (0.043)
Baghouse	4	3	64 (0.028)	32 (0.014)	44 (0.019)
Clinker cooler:					
ESP	1	1	46 (0.02)	46 (0.02)	46 (0.02)
Baghouse	2	2	122 (0.053)	4.6 (0.002)	64 (0.028)
Various mills:					
Baghouse	10	3	53 (0.023)	4.6 (0.002)	18 (0.008)

- Production-based rate - Monthly average of 3.5 kg/Mg (7.0 lb/ton) of aluminum produced and annual average of 2.5 kg/Mg (5.0 lb/ton) of aluminum produced.

The most stringent state VE limitation is 0 percent opacity [MD].

NSPS Subpart S applies to primary aluminum reduction plants that were constructed or installed after October 23, 1974. The standard includes limits for fluorides and opacity. VE from potroom groups cannot equal or exceed 10 percent opacity. VE from an anode bake plant cannot exhibit greater than or equal to 20 percent opacity.

Examples of total PM emission test data from two potlines are summarized below (Fitzpatrick, *et al*, 1991):

- ESP control - 3.9 mg/dscm (0.0017 gr/dscf)
- Baghouse control - 0.9 mg/dscm (0.0004 gr/dscf)

PULP MILLS

State regulations were reviewed for 46 states (Nebraska, South Dakota, Vermont, and Wyoming were not included) to determine the most stringent total PM and opacity limitations for recovery furnaces, smelt dissolving tanks and lime kilns at kraft pulp mills, and blow pits and recovery systems at sulfite pulp mills. There is an applicable NSPS for kraft pulp mills.

The most stringent state total PM emissions limitations for recovery furnaces, smelt tanks and lime kilns at kraft pulp mills are summarized below:

	Recovery furnace	Smelt tank	Lime kiln
Concentration, mg/dscm (gr/dscf)	69 (0.03) [MD]	69 (0.03) [MD]	69 (0.03) [MD]
Emission rate	Curve 2 on Figure 4-1	Curve 2 on Figure 4-1	Curve 2 on Figure 4-1
Production-based rate	1.15 kg/Mg (2.3 lb/ton) equivalent unbleached dried pulp [KY]. 1.4 kg/1.4 Mg (3 lb/3,000 lb) of black liquor solids feed [FL].	0.25 kg/Mg (0.5 lb/ton) equivalent unbleached dried pulp [AL, ID, KY, LA, ME, NH, NM, OR, TN]. 0.1 kg/Mg (0.2 lb/ton black liquor solids [PA].	0.25 kg/Mg (0.5 lb/ton equivalent air dried pulp [NC].

The most stringent state opacity limitation is 0 percent [MD].

NSPS Subpart BB applies to kraft pulp mills that were installed or modified after September 24, 1976. The NSPS requirements are summarized as follows:

	Total PM	Opacity
Recovery furnace	100 mg/dscm (0.044 gr/dscf) corrected to 8% oxygen	Not $\geq$ 35%
Smelt dissolving tank	0.1 g/kg (0.2 lb/ton) black liquor solids (dry weight)	-
Lime kiln	150 mg/dscm (0.067 gr/dscf) corrected to 10% oxygen if gaseous fossil fuel is burned. 130 mg/dscm (0.13 gr/dscf) corrected to 10% oxygen if liquid fossil fuel is burned.	-

Examples of total PM emissions test data are summarized on Table 4-8 (OAQPS, 1976).

The most stringent state total PM emissions limitations for sulfite pulping are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf [MD].

- o Emission rate - 0.9 kg/24 hr (2 lb/24 hr) from blowpits, washer vents, storage tanks, digester relief and recovery operations [AK]. Also, refer to Curve 2 on Figure 4-1.

- o Production-based rate - For recovery systems, 2 kg/Mg (4 lb/ton) of unbleached dried pulp [OR].

The most stringent state opacity limitation is 0 percent [MD].

SECONDARY ALUMINUM REDUCTION FACILITIES

Regulations for all 50 states were reviewed to determine the most stringent total PM and opacity limitations for secondary aluminum reduction facilities. The most stringent total PM emissions limitations are as follows:

- o Concentration - 69 mg/dscm (0.03 gr/dscf) [FL, MD]. Another state [NJ] requires the least restrictive of the following: 1) an emission concentration of less than of equal to 46 mg/dscm (0.02 gr/dscf) with an upper cap of 14 kg/hr (30 lb/hr) or 2) a control efficiency of 99 percent.

- o Emission rate - For melting and refining, as calculated by the following equation: $A = 0.76(10W)^{0.42}$; where A is the allowable rate (lb/hr) and W is the aluminum feed rate (ton/hr) [PA]. For other operations (sweating), allowable varies by production rate and is determined by the following equation: $A = 0.76(50W)^{0.42}$; where A is the allowable rate (lb/hr) and W is the production rate (ton/hr) [PA] or one of the curves on Figure 4-1.

The most stringent state opacity limit is 0 percent [MD].

Total PM emissions test data from a reverberatory furnace equipped with a scrubber are 37.9 mg/dscm (0.0165 gr/dscf) (Fitzpatrick, *et al*, 1991).

TABLE 4-8. SUMMARY OF EXAMPLE TOTAL PM EMISSIONS TEST DATA FOR KRAFT PULP MILLS

mg/dscm (gr/dscf)

Process operation: control device	No. of tests	No. of facilities	Maximum	Minimum	Average
Recovery furnace: ESP	9	4	120 (0.052)	7 (0.003)	53 (0.023)
Smelt dissolving tank: Scrubber	2	2	80 (0.035)	55 (0.024)	69 (0.030)
Lime kiln[a]: Scrubber	4	2	110 (0.048)	62 (0.027)	92 (0.040)

[a]Natural gas-fired.

SUGAR PRODUCTION PLANTS

State regulations were reviewed for California, Colorado, Idaho, Kansas, Michigan, Minnesota, Montana, Nebraska, North Dakota, Ohio, Oregon, Texas, Wisconsin and Wyoming to determine the most stringent total PM and opacity limitations for sugar production from sugar beets.

The most stringent total PM emission limitation is calculated from the following equations:

- $E = 0.045(PW)^{0.60}$ for production weights below 4.2 Mg/hr (9,250 lb/hr), or
- $E = 1.10\ (PW)^{0.25}$ for production weights greater than or equal to 4.2 Mg/hr (9,250 lb/hr); where E is the allowable rate (lb/hr) and PW is process weight (lb/hr) [ID].

There are two similarly strict opacity limitations:

- No more than an aggregate of 3 min/hr greater than or equal to 20 percent opacity [OR].
- Not greater than or equal to 20 percent opacity (6-minute) average [MT, NE].

SURFACE MINING OPERATIONS

State regulations for Arkansas, Arizona, Colorado, Illinois, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, North Dakota, South Dakota, Tennessee, Utah, Virginia, and Wyoming where reviewed to determine the most stringent limitations for surface mining. This source category includes such operations as scraping, grading and overburden removal. Ore concentrating is discussed under the Nonferrous Smelters portion of this Section. Nonmetallic mineral processing is discussed under the Nonmetallic Mineral Plants portion of this Section.

The emissions from this source category are fugitive dust. The most stringent fugitive dust limiations are as follows:

- Can not cause or permit handling, transporting or storing of any material in a manner which allows or may allow a controllable particulate to become airborne. Cannot use unpaved areas without reasonable precautions [NV].

- Fugitive emissions shall not be visible beyond property line. An operating program to minimize dust is required for certain sources [IL].

- Take reasonable precautions or measures to minimize fugitive emissions [CO, MN, ND, TN, VA, WY].

TURBINES (OIL-FIRED)

State regulations were reviewed for all fifty states to determine the most stringent total PM and opacity limitations for oil-fired turbines. The most stringent total emissions limitations are as follows:

- Concentration - 69 mg/dscm (0.03 gr/dscf) [MD, FL].

- Emission rate - Calculated from the following equation: $E = 1.02Q^{0.769}$; where E is the allowable rate (lb/hr) and Q is the heat input (MMBtu/hr) [AZ].

- Production-based rate - for units less than 53 GJ/hr (50 MMBtu/hr), 52 ng/J (0.12 lb/MMBtu). For units between 53 and 260 GJ/hr (50 and 250 MMBtu/hr), 34 ng/J (0.08 lb/MMBtu) [ME].

The most stringent opacity limitations states than there shall be no visible air contaminants, other than water, for longer than 10 consecutive seconds [MA].

Examples of total PM emissions test data for oil-fired turbines from 12 turbines ranges from 6.7 to 30.5 ng/J (0.02 to 0.07 lb/MMBtu) with an average of 15.5 ng/J (0.04 lb/MMBtu) (Shih, *et al*, 1979).

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SECTION 5

COSTS OF CONTROL

This Section describes procedures for estimating (1) total capital investment and (2) total annual costs of the control measures which are generally used to control PM-10 emissions. First it discusses the general sequence for preparing an estimate of total capital investment and total annual costs. The Section then defines the elements of total capital investment and of total annual costs in separate subsections. Each subsection also discusses estimating procedures and provides an example calculation. Sources of information needed to perform these estimating procedures are provided throughout the discussion, where appropriate.

GENERAL PROCEDURES

There are a number of different types of cost estimating procedures (Garrett, 1989) differing in the degree of detail required for preparation and the accuracy of the result. The procedures described here are for a "study" estimate, sometimes called a "factored" estimate. The accuracy should be within ± 30 percent (Garrett, 1989; Peters, 1980). The general sequence of steps for preparing a study estimate is:

1. Prepare a flowsheet for the control operation showing all the major control equipment and any auxiliary equipment required such as collection hoods, ductwork, fans, stacks, etc.

2. As necessary, calculate heat and material balances around each equipment item.

3. Size the equipment and determine the required material of construction. In some cases the equipment vendors or their representatives will size the equipment and specify the material of construction.

4. Estimate the cost of each equipment item either by obtaining vendor quotes or from published information.

5. Sum the cost of the equipment items plus the cost of instrumentation (if not already included in the

equipment cost), taxes, and freight to obtain the total purchased equipment cost.

6. The capital cost (total capital investment) estimate is then calculated from the total purchased equipment cost.

7. The total annual cost estimate is calculated based on information from the flowsheet and the capital cost estimate.

Flowsheet preparation, heat and material balance preparation, and equipment sizing procedures are beyond the scope of this document. For flowsheet preparation and heat and material balance preparation, consult basic chemical engineering texts such as Basic Principles and Calculations in Chemical Engineering (Himmelblau, 1982). Equipment sizing procedures can be found in the OAQPS Control Cost Manual (OAQPS, 1990) and the Chemical Engineers Handbook (Perry, 1984).

The remainder of this Section defines and discusses procedures that will allow you to arrive at total capital investment estimates and total annual cost estimates.

TOTAL CAPITAL INVESTMENT

Elements of Total Capital Investment

Total capital investment can be broadly broken into two categories, non-depreciable investment, which includes land and working capital, and depreciable investment, which includes all of the direct and indirect costs associated with the control system, including off-site facilities if applicable.

The non-depreciable investments (land and working capital) are not major factors. Working capital is the cost of raw materials and inventory, one month's accounts receivable and payable, and wages. It is rarely a factor for control equipment. Most control equipment does not occupy sufficient land for land to be a significant cost factor.

The depreciable investment (all of the direct and indirect costs) requires further explanation. Total direct costs comprise purchased equipment costs, direct installation costs, and related site preparation and building costs not already factored into the purchased equipment costs. Purchased equipment costs usually include:

- Primary control device
- Auxiliary equipment (including ductwork)
- Instrumentation

- Sales taxes
- Freight.

Direct installation costs include:

- Foundation and supports
- Handling and erection
- Electrical
- Piping
- Insulation
- Painting.

Total indirect costs comprise the following indirect installation costs:

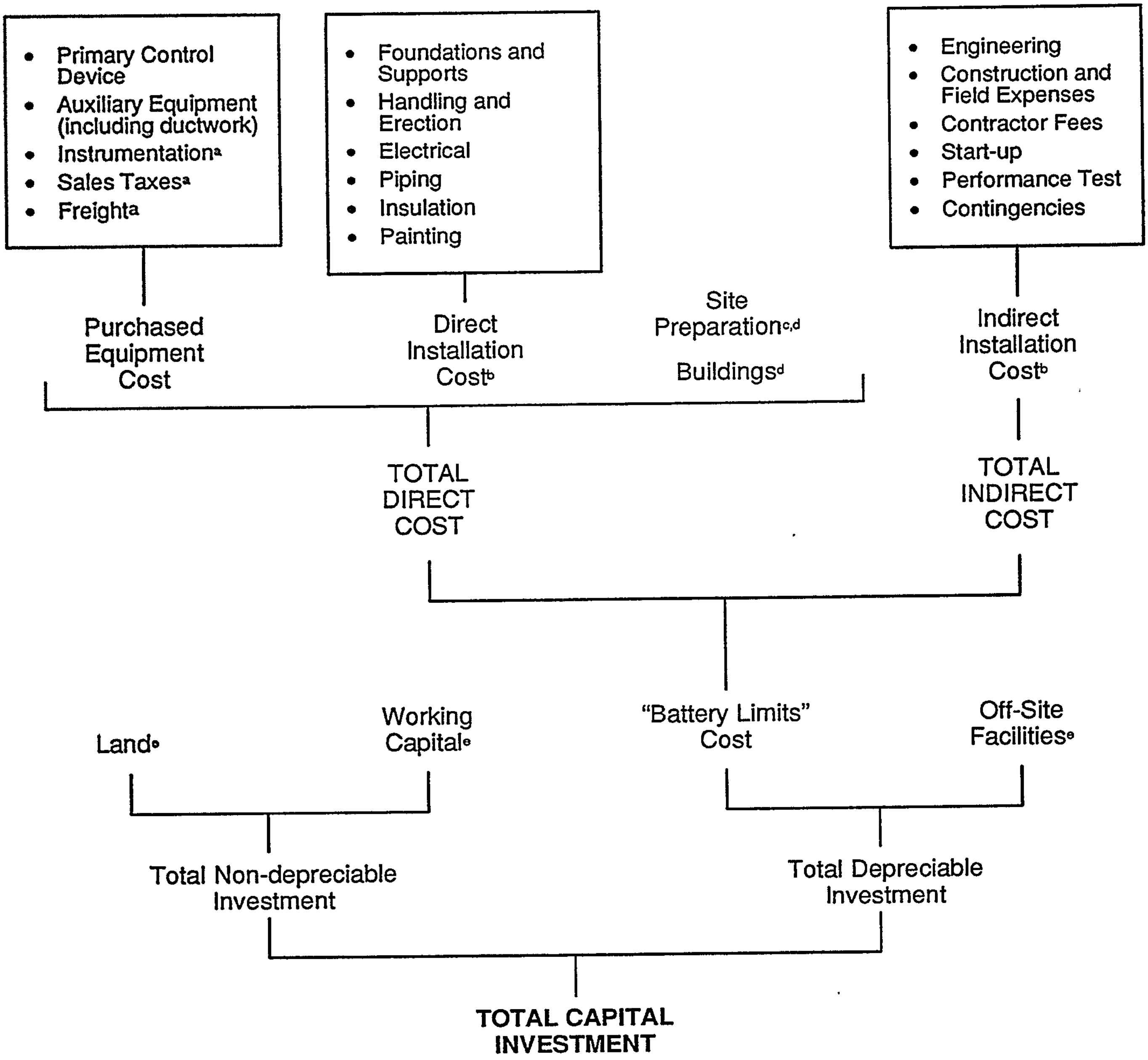
- Engineering
- Construction and field expenses
- Contractor fees
- Start-up
- Performance test
- Contingencies.

These elements of total capital investment are shown in Figure 5-1 and are taken from the OAQPS Control Cost Manual (OAQPS, 1990). Note on Figure 5-1 that the sum of the purchased equipment, total direct and indirect costs, site preparation, and buildings comprises the battery limits cost. The battery limits cost is an "estimate for a required investment for a specific job without regard to required supporting facilities which are assumed to exist already." (Humphreys, 1987). Examples of supporting facilities include an electrical substation or a cooling tower. It is valid to assume no supporting facilities when determining the cost of adding pollution control technology to an existing plant. It would also be valid for either new or existing plants unless such special supporting facilities are required specifically for the control device.

Estimating Total Capital Investment

"Of the many factors which contribute to poor estimates of capital investments, the most significant one is usually traceable to sizeable omissions of equipment, . . . or auxiliary facilities . . ." (Peters, 1991). Hence it is important that the entire control installation be thought through from the point where the pollutants are emitted to the point where the cleaned gas is discharged to the atmosphere to make sure all the required equipment is included.

There are a number of ways to calculate total capital investment. However, the procedure most commonly used in preparing study estimates begins by first obtaining the total



[a] Typically factored from the sum of the primary control device and auxilliary equipment costs.

[b] Typically factored from the purchased equipment cost.

[c] Usually required only at "grass roots" installations.

[d] Unlike the other direct and indirect costs, costs for these items usually are not factored from the purchased equipment cost. Rather, they are sized and costed separately.

[e] Normally not required with add-on control systems.

Figure 5-1. Elements of total capital investment.

purchased equipment cost. The remaining elements of the total capital investment are then calculated as percentages or "factors" of the total purchased equipment cost. This procedure is known as the "factored" approach to capital cost estimating.

Purchased Equipment Cost --

The costs of the individual equipment items which make up the control system can be obtained either from vendors' or fabricators' quotations or from published sources such as the OAQPS Control Cost Manual (OAQPS, 1990), the Chemical Engineers Handbook (Perry, 1984) or publications such as Chemical Engineering. Vendor's quotations will be in current dollars, but published cost data, will of necessity, be out of date. Cost indexes must be used to adjust these costs to current dollars. Cost indexes for equipment used in control systems can be found in Chemical Engineering which is published by McGraw-Hill Publications. These indexes are updated monthly. The current cost of the equipment item is obtained by multiplying the original cost of the equipment by the ratio of the cost index for the time the original cost was obtained to the current cost:

$$\text{current cost} = (\text{original cost}) \times \frac{\text{current index}}{\text{index at time original cost was obtained}}$$

If possible, cost data more than five years old should not be adjusted. If available, newer data should be used. The costs so obtained, and in most cases the vendors' quotations, will not include sales taxes, or the cost of transporting the equipment from the factory to the site where it is to be used. The cost of instrumentation must also be added if it is not already included in the cost of the control device. Without specific data, the cost of freight and taxes is estimated at 8 percent of the equipment cost (OAQPS, 1990). Instrumentation is usually a small part of the cost of the majority of control system installations. If no specific information is available, it can be estimated as 10 percent of the equipment cost (OAQPS, 1990). The total purchased equipment cost is then obtained by summing the equipment cost, taxes, freight, and instrumentation.

A contingency may also be included in calculating the total capital investment. A contingency "... is an estimate of the accuracy considering the development ... of the project" (Humphreys, 1987).

Total Capital Investment --

The components of the total capital investment are given in Table 5-1 for various control devices. The cost of each component of capital investment is obtained by multiplying the total purchased equipment cost by the factor for that component. The individual components are then summed to obtain the total capital investment.

The factors given in Table 5-1 (OAQPS, 1990; ORD, 1991) are for new construction, that is systems that are installed as the plant they are controlling is under construction. When the control system is sized for and installed on an existing process (i.e., retrofitted) the factors do not apply. Each retrofit installation is unique. Cost elements that can change in a retrofit installation are:

- Handling and erection - special care and time may be required if space for the installation is limited and the fit is tight.

- Piping, insulation, painting, and electrical may also increase. Retrofit installations may require longer than average pipe, duct and wire runs.

- Engineering and supervision - more than average may be required.

- Site preparation - this cost could go down, since most of the work would have been done when the plant was built.

For these reasons the contingency (i.e., uncertainty) factor should be increased when estimating retrofit installations. In the absence of specific information, 10 percent of the purchased equipment cost is suggested.

For illustration purposes, Table 5-2 is an example of the calculation of the total capital investment for a fabric filter using the factors given in Table 5-1. The fabric filter is designed to control fly ash emissions in a 1,416 m^3/min (50,000 acfm) flue gas stream at 436 K (325°F) from a new coal-fired boiler. The table is taken from the OAQPS Control Cost Manual (OAQPS, 1990).

TOTAL ANNUAL COST

Elements of Total Annual Cost

The total annual cost is generally broken down into direct and indirect costs. Direct costs are those which are

TABLE 5-1. CAPITAL INVESTMENT ELEMENTS AND FACTORS[a,b] FOR VARIOUS CONTROL DEVICES

Cost elements	Cost Factors		
	ESP	Venturi scrubbers	Fabric filters
DIRECT COSTS			
Purchased Equipment Cost[c]	1.00	1.00	1.00
Other Direct Costs[d]			
Foundation and supports	0.04	0.06	0.04
Erection and handling	0.50	0.40	0.50
Electrical	0.08	0.01	0.08
Piping	0.01	0.05	0.01
Insulation	0.02	0.03	0.07
Painting	0.02	0.01	0.02
Total Direct Cost	1.67	1.56	1.72
INDIRECT COSTS			
Engineering and supervision	0.20	0.10	0.10
Construction and field expenses	0.20	0.10	0.20
Contractor fees	0.10	0.10	0.10
Start-up	0.01	0.01	0.01
Performance test[e]	0.01	0.01	0.01
Model study	0.02	–	–
Contingencies[f]	0.03	0.03	0.03
Total Indirect Cost	0.57	0.35	0.45
TOTAL CAPITAL INVESTMENT	2.24	1.91	2.17

[a]Taken from Handbook, Control Technologies for Hazardous Air Pollutants for new source construction (ORD, 1991).

[b]As fractions of total purchased equipment cost. They must be applied to the total purchased equipment cost.

[c]Total of purchased costs of major equipment and auxiliary equipment and others, which include instrumentation and controls at 10%, taxes and freight at 8% of the equipment purchase cost. Note that instrumentation may be included in the cost of the control device and would therefore not need to be calculated separately.

[d]Site preparation and buildings would be included in this category if required.

[e]The performance test determines that all items of equipment operate properly. It does not include the cost of determining that the control system emissions meet requirements; this is an operating cost.

[f]Contingency costs are estimated to equal 3% of the purchased equipment cost (OAQPS, 1990). The contingency cost should be increased when estimating a retrofit installation. In the absence of specific information 10% of the purchased equipment cost is suggested.

TABLE 5-2. CAPITAL INVESTMENT FOR FABRIC FILTER SYSTEM -- EXAMPLE CALCULATION

Cost item			Cost
DIRECT COSTS			
Purchased equipment costs			
Fabric filter (with insulation)	$ 80,231		
Bags and cages	18,092		
Auxiliary equipment[a]	62,700		
Sum = A		$161,023	
Sales taxes, 0.03A		4,831	
Freight, 0.05A		8,051	
Instrumentation, 0.1A		16,102	
Purchased equipment cost= B			$190,007
Installation costs			
Foundation and supports, 0.04B		7,600	
Handling and erection, 0.50B		95,004	
Electrical, 0.08B		15,201	
Piping, 0.01B		1,900	
Insulation for ductwork, 0.07B		13,300	
Painting, 0.02B		3,800	
Installation cost			136,805
Site preparation		Not required	
Facilities and buildings		Not required	
Total Direct Cost			326,812
INDIRECT COSTS			
Engineering, 0.10B		19,001	
Construction and field expenses, 0.20B		38,001	
Contractor fees, 0.10B		19,001	
Start-up, 0.01B		1,900	
Performance test, 0.01B		1,900	
Contingencies, 0.03B		5,700	
Total Indirect Cost			85,503
TOTAL CAPITAL INVESTMENT			$412,315

[a]For the installation illustrated by this example, the auxiliary equipment is:

Ductwork	$14,000
Fan	14,000
Motor	7,000
Starter	3,500
Dampers	7,200
Compressor	6,000
Screw conveyor	4,000
Stack	7,000
Total	$62,700

proportional, or in some cases roughly so, to the plant operating rate. These costs include operating labor and supervision, maintenance labor and materials, parts that must be replaced on a routine basis (e.g., bags in a fabric filter), raw materials (if any), utilities, and any waste disposal costs. Indirect costs are plant overhead charges, taxes, insurance, administrative charges, and capital recovery. These costs are fixed and tend to be incurred whether or not the control system is operating.

If the control system recovers material or energy which can be used, recycled or sold, the value of the material or energy must be included as a recovery credit which will reduce the total annual costs. Figure 5-2 taken from the OAQPS Control Cost Manual (OAQPS, 1990) shows the elements of total annual cost.

Estimating Total Annual Cost

Direct Costs --

The procedures for estimating direct annual costs are discussed below.

Operating Labor -- Operating labor is dependent on the complexity of the control system, the degree of automation, and to a lessor extent on the size of the system, and is usually estimated based on the estimator's experience, considering the foregoing factors. Typical labor requirements can be found in the example problems in the OAQPS Control Cost Manual (OAQPS, 1990). Operating labor is usually stated on an hours-per-shift basis. The number of hours (or number of eight hour shifts) the equipment will operate annually is usually determined when the equipment is sized. Wage rates for operating labor are industry dependent. Employment and Earnings, a monthly publication of the U.S. Department of Labor, Bureau of Statistics, provides wage rates for most industries.

The cost of supervision must be added to the labor cost. Unless specific information is available, supervision is usually estimated as 15 percent of the cost of operating labor (OAQPS, 1990).

Maintenance -- Maintenance labor can be estimated and calculated in the same manner as operating labor. The maintenance labor rate is usually higher than the operating labor rate because greater skills are required. A 10 percent labor premium is typical (OAQPS, 1990). The number of maintenance hours will depend on the complexity of the control system, the composition of the emission stream (which will influence its corrosivity) and on the severity of the service environment. Maintenance materials are then usually estimated as equal to maintenance labor.

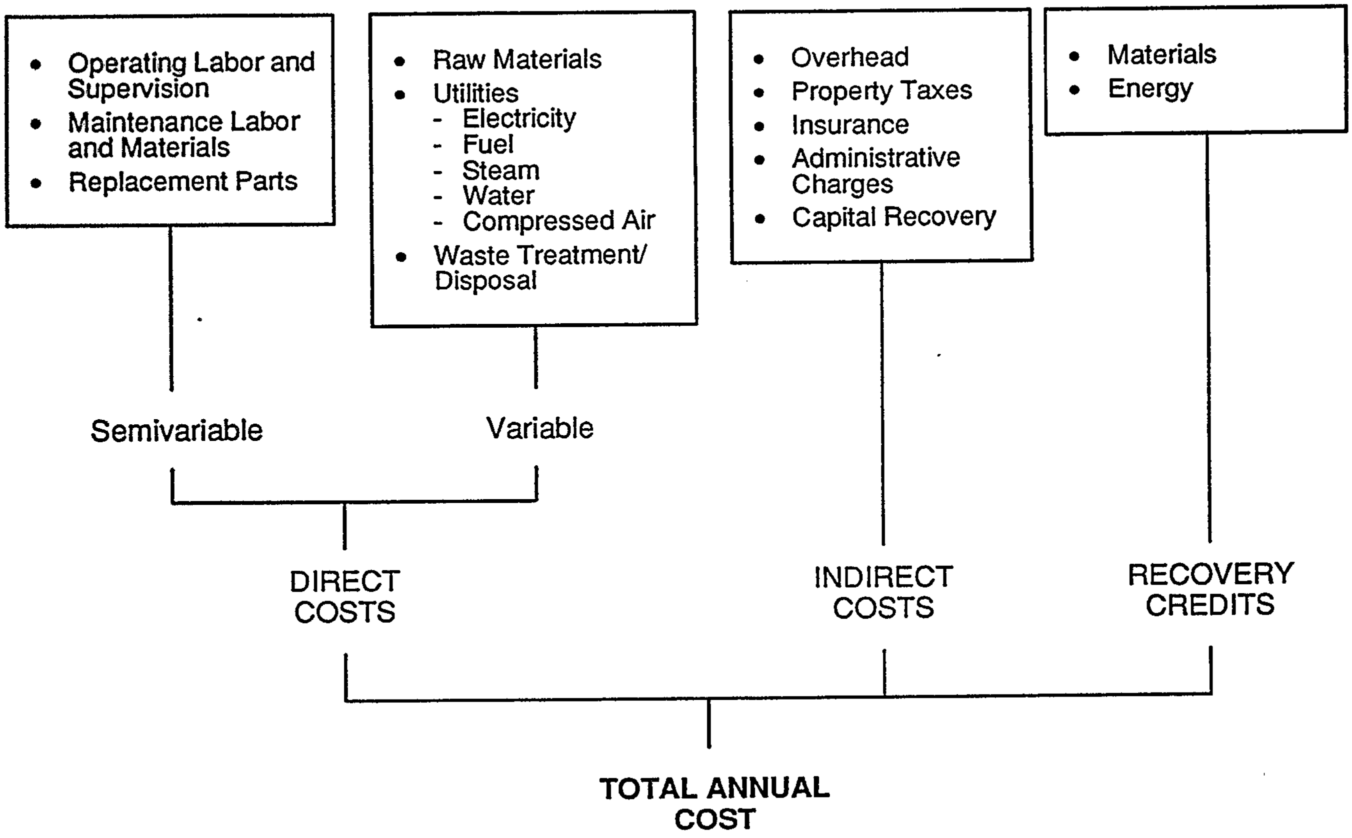


Figure 5-2. Elements of total annual cost.

An alternative way to estimate maintenance costs, if no data on actual hourly requirements is available, is as a fixed percentage of the total capital investment (Humphreys, 1987). The percentage varies from 3 to 5 percent for a simple system controlling a relatively non-corrosive emission stream to 12 percent for a complex system operating in a corrosive environment. Maintenance costs are usually distributed 50 percent to labor, 50 percent to materials.

Replacement Parts -- The cost of replacement parts, such as filter bags, that require replacement on a routine basis and are a significant expense is not included in the maintenance cost but is included in the direct costs as a separate item. The annual cost of replacement parts includes both the cost of the part and the cost of the labor to install it. In the OAQPS Control Cost Manual methodology (OAQPS, 1990) replacement parts are treated like any other investment in that they are considered an expenditure that must be amortized over the life of the part. The annual cost of the replacement part is then:

$$C = (R + L)CRF \qquad (5.1)$$

where:

C = annual cost of the replacement parts, \$/year
R = initial cost of the part, including taxes and freight,\$
L = part replacement labor, \$
CRF = capital recovery factor whose value is a function of the annual interest rate and the useful life of the part. (See discussion of the capital recovery factor and equation 5.4 below.)

When the annual cost of replacement parts is calculated using equation 5.1 and included in the annual cost, double counting must be avoided. This is done by reducing the total capital investment (P in equation 5.3 below) by the sum of the cost of the parts, including taxes and freight and labor for installing them, when the annual capital recovery charge is calculated to avoid double counting.

Raw Materials -- Raw materials are generally not required. A possible exception would be an alkaline material added to the circulating water in a venturi scrubber to neutralize acidic gasses such as sulfur dioxide or hydrogen chloride in the emission stream. The quantity of raw material required is directly proportional to the quantity of material treated and is calculated by a material balance. The cost of chemicals can be obtained from the Chemical Marketing Reporter, published by the Schnell Publishing Company, Inc., New York, NY, or from chemical manufacturers or suppliers.

Utilities -- Electricity, fuel, steam, cooling water, and compressed air are included in this category. Consumption of these items is determined from energy and material balances calculated around the control device. These calculations are made during the design of the control system.

Because nearly every system requires an electric fan to move the process emission gas through the control device, a general expression for fan power requirements is provided (OAQPS, 1990):

$$K = 0.00025164 Q \Delta P \tag{5.2a}$$

where:

K = power required by the fan, kilowatts
Q = system flow rate, actual cubic meters per minute
ΔP= system pressure drop, in millimeters of water.

In English units the equation is:

$$K = 0.000181 Q \Delta P \tag{5.2b}$$

where:

K = power required by the fan, kilowatts
Q = system flow rate, actual cubic feet per minute
ΔP= system pressure drop, inches of water.

The equation assumes a combined fan/motor efficiency of 65 percent.

The cost of electricity and natural gas vary by region and are best obtained from the local supplier. The cost of utilities generated in-plant such as compressed air and steam should, if possible, be obtained from the plant.

Utilities are a direct cost. The utility usage rate (i.e., kilowatts for a fan) must be multiplied by the annual operating hours to obtain the annual consumption. The annual consumption is then multiplied by the cost per unit to obtain the annual cost.

Waste Disposal -- There can be a significant charge associated with the emitted material captured by a control system that can neither be sold or recycled. Some streams, such as the thin suspension from a venturi scrubber, may have to be processed to remove the solids before being discharged. Additional treatment such as pH adjustment may be required. If a liquid stream is discharged to a treatment works, there would be a charge. There would also be a charge for landfilling or possibly incinerating a solid stream.

Waste disposal charges can vary widely. Landfilling costs for non-hazardous solid waste can vary from $10 to over a $100 per ton depending on the area of the country (Siddens, 1990). Disposal costs for hazardous solid wastes are much higher. Waste water treatment costs range from $0.25 to $0.50/m^3 ($1.00 to $2.00/1,000 gallons) or more, depending on the degree of treatment required (OAQPS, 1990), plus the costs for disposing of any solids generated by the treatment.

Indirect Costs --

The procedures for estimating indirect annual costs are summarized below.

Overhead -- There are generally two categories of overhead: payroll and plant. Payroll overhead is comprised of expenses incurred as a result of operating, maintenance and supervisory labor and includes such items as Social Security fund payments, pension fund costs, workmen's compensation payments, and vacations.

Plant overhead accounts for the cost of plant protection services, plant lighting, parking lots, interplant communications, and shipping and receiving facilities. For study estimates these two types of overhead are combined. Peters and Timmerhaus (Peters, 1980) recommend a charge of 50 to 70 percent of the total cost for operating, maintenance and supervisory labor and maintenance materials. Sixty percent is recommended by the OAQPS Control Cost Manual (OAQPS, 1990).

Property Taxes, Insurance and Administrative Charges -- These three costs are proportional to the plant investment and are calculated at 1, 1 and 2 percent of the total capital investment, respectively. These values are standard in all OAQPS cost analyses (OAQPS, 1990).

Capital Recovery -- The capital recovery charge allows the owner/operator of the control equipment to recover the capital cost of the system plus interest over the useful life of the system as a series of uniform annual payments (Grant, 1982). The annual capital recovery cost is calculated as

$$CRC = CRF \times P \qquad (5.3)$$

where:

CRC = the capital recovery cost
CRF = the capital recovery factor
P = the total capital investment.

The capital recovery factor is:

$$CRF = \frac{i(1 + i)^n}{(1 + i)^n - 1} \tag{5.4}$$

where:

i = the interest rate; it is usually set at 10 percent in keeping with the current Office of Management and Budget recommendations for use in regulatory analysis.

n = the economic life of the control system, typically 10 to 20 years for a system but may be much shorter for replacement parts.

Recovery Credit --

When there are recovery credits (e.g. raw material or product recovered by a fabric filter), they are included as a separate subheading following Total Indirect Annual Costs.

Total Annual Cost --

The total annual cost then is the sum of the direct costs (raw materials, utilities, labor, maintenance, and waste treatment/disposal) and the indirect costs (overhead, property taxes, insurance, administrative charges, and capital recovery) less any credits for material or energy recovery that will be achieved by the control system.

For illustration purposes, Table 5-3, taken from the OAQPS Control Cost Manual (OAQPS, 1990) shows the calculation of Total Annual Cost for a fabric filter system presented in Table 5-2, above. In this example, waste disposal is a major component of the annual cost, and there are no recovery credits.

TABLE 5-3. ANNUAL COSTS FOR FABRIC FILTER SYSTEM -- EXAMPLE CALCULATION

DIRECT ANNUAL COST	
<u>Operating Labor</u>	
Operator	
$\frac{2\ hr}{shift} \times \frac{3\ shifts}{day} \times \frac{360\ days}{yr} \times \frac{\$12}{hr} =$	\$ 25,920
Supervisor	
15% of operator labor = .15 x 25,920 =	3,888
<u>Maintenance</u>	
Labor	
$\frac{3\ hr}{day} \times \frac{360\ days}{yr} \times \frac{\$13.20}{hr} =$	14,256
Material	
100% of maintenance labor =	14,256
<u>Replacement parts</u>, bags[a]	
[(13,220 x 1.08) + 2,809] x 0.5762 =	9,845
<u>Raw materials</u>	Not required
<u>Utilities</u>	
Electricity (fan only)	
$0.00025164 \times \frac{1{,}416\ m^3}{min} \times 261.6\ mm\ H_2O \times \frac{8{,}640\ hr}{yr} \times \frac{\$0.06}{kWh} =$	48,323
Compressed air (a pulse jet filter requires 2 $sm^3/1000m^3$ of gas filtered, at a cost of \$5.65 per 1000 sm^3)	
$\frac{2\ sm^3}{1000\ m^3} \times \frac{1416\ m^3}{min} \times \frac{\$5.65}{1000 sm^3} \times \frac{60\ min}{hr} \times \frac{8640\ hr}{yr} =$	8,295
<u>Waste disposal</u> (at \$22/Mg, disposed of on-site, assuming 100% collection efficiency)	
$\frac{9.2\ g}{m^3} \times \frac{1416\ m^3}{min} \times \frac{60\ min}{hr} \times \frac{8640\ hr}{yr} \times \frac{1 Mg}{10^6 g} \times \frac{\$22}{Mg} =$	148,573
Total Direct Annual Costs	\$ 273,355

(continued)

TABLE 5-3. (Continued)

INDIRECT ANNUAL COSTS	
Overhead	
60% (labor and maintenance materials) =	
0.6(25,920 + 3,888 + 14,256 + 14,256) =	$ 34,992
Property tax	
1% of Total Capital Investment = 0.01($412,000) =	4,120
Insurance	
1% of Total Capital Investment = 0.01($412,000) =	4,120
Administrative charges	
2% of Total Capital Investment = 0.02($412,000) =	8,240
Capital recovery[b]	
0.1175 (412,315 - 2,809 - 13,220 x 1.08) =	46,439
Total Indirect Annual Costs	97,911
RECOVERY CREDITS	Not applicable
TOTAL ANNUAL COST (ROUNDED)	$371,000

[a]The cost of the replacement bags is $13,220. The 1.08 factor is for freight and sales taxes. For bag replacement labor, 10 minutes per bag for each of 795 bags was assumed. At a maintenance labor rate of $21.12 (including 60% overhead), the labor cost is $2,809 for 133 hours. The replacement cost was] calculated using equation 5.1. The CRF, in equation 5.1 is calculated using equation 5.4 for a 2 year life and 10% interest:

$$CRF = \frac{0.1\ (1+0.1)^2}{(1+0.1)^2 - 1} = 0.5762$$

[b]For a 20 year equipment life and a 10% interest rate, CRF = 0.1175. The total capital investment (from Table 5-2) is reduced by the total cost of replacing the bags to avoid double counting.

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TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

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4. TITLE AND SUBTITLE Procedures for Identifying Reasonably Available Control Technology for Stationary Sources of PM-10		5. REPORT DATE September 1992 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Fitzpatrick, M. J.; R. Ellefson, et.al		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS JACA Corp. 550 Pinetown Road Fort Washington, PA 19034		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-W9-0080
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15. SUPPLEMENTARY NOTES

16. ABSTRACT

This guidance document sets forth procedures and identifies sources of information that will assist State and local air pollution control agencies in determining Reasonably Available Control Technology (RACT) for PM-10 (particulate matter having a nominal aerometri diameter of 10 microns or less) emission from existing stationary sources on a case-bycase basis. It provides an annotated bibliography of documents to aid in identifying the activities that cause PM-10 emissions as well as applicable air pollution control measures and their effectiveness in reducing emissions. The most stringent state total particulate matter (PM) emission limits are identified for several categories of PM-10 sources and compared to available emission test data. Finally, guidance is provided on procedures for estimating total capital investment and total annual cost of the control measures which are generally used to control PM-10 emissions.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Particulate matter, PM-10, emission limits, control technology, cost of control		

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EXECUTIVE DEPARTMENT
STATE OF CALIFORNIA

EXECUTIVE ORDER N-79-20

WHEREAS the climate change crisis is happening now, impacting California in unprecedented ways, and affecting the health and safety of too many Californians; and

WHEREAS we must accelerate our actions to mitigate and adapt to climate change, and more quickly move toward our low-carbon, sustainable and resilient future; and

WHEREAS the COVID-19 pandemic has disrupted the entire transportation sector, bringing a sharp decline in demand for fuels and adversely impacting public transportation; and

WHEREAS as our economy recovers, we must accelerate the transition to a carbon neutral future that supports the retention and creation of high-road, high-quality jobs; and

WHEREAS California's long-term economic resilience requires bold action to eliminate emissions from transportation, which is the largest source of emissions in the State; and

WHEREAS the State must prioritize clean transportation solutions that are accessible to all Californians, particularly those who are low-income or experience a disproportionate share of pollution; and

WHEREAS zero emissions technologies, especially trucks and equipment, reduce both greenhouse gas emissions and toxic air pollutants that disproportionately burden our disadvantaged communities of color; and

WHEREAS California is a world leader in manufacturing and deploying zero-emission vehicles and chargers and fueling stations for cars, trucks, buses and freight-related equipment; and

WHEREAS passenger rail, transit, bicycle and pedestrian infrastructure, and micro-mobility options are critical components to the State achieving carbon neutrality and connecting communities, requiring coordination of investments and work with all levels of governments including rail and transit agencies to support these mobility options; and

WHEREAS California's policies have contributed to an on-going reduction in in-state oil extraction, which has declined by over 60 percent since 1985, but demand for oil has not correspondingly declined over the same period of time; and

WHEREAS California is already working to decarbonize the transportation fuel sector through the Low Carbon Fuel Standard, which recognizes the full life cycle of carbon in transportation emissions including transport into the State; and

WHEREAS clean renewable fuels play a role as California transitions to a decarbonized transportation sector; and

WHEREAS to protect the health and safety of our communities and workers the State must focus on the impacts of oil extraction as it transitions away from fossil fuel, by working to end the issuance of new hydraulic fracturing permits by 2024; and

WHEREAS a sustainable and inclusive economic future for California will require retaining and creating high-road, high-quality jobs through sustained engagement with communities, workers and industries in changing and growing industries.

NOW THEREFORE, I, GAVIN NEWSOM, Governor of the State of California by virtue of the power and authority vested in me by the Constitution and the statutes of the State of California, do hereby issue the following Order to pursue actions necessary to combat the climate crisis.

IT IS HEREBY ORDERED THAT:

1. It shall be a goal of the State that 100 percent of in-state sales of new passenger cars and trucks will be zero-emission by 2035. It shall be a further goal of the State that 100 percent of medium- and heavy-duty vehicles in the State be zero-emission by 2045 for all operations where feasible and by 2035 for drayage trucks. It shall be further a goal of the State to transition to 100 percent zero-emission off-road vehicles and equipment by 2035 where feasible.

2. The State Air Resources Board, to the extent consistent with State and federal law, shall develop and propose:

   a) Passenger vehicle and truck regulations requiring increasing volumes of new zero-emission vehicles sold in the State towards the target of 100 percent of in-state sales by 2035.

   b) Medium- and heavy-duty vehicle regulations requiring increasing volumes of new zero-emission trucks and buses sold and operated in the State towards the target of 100 percent of the fleet transitioning to zero-emission vehicles by 2045 everywhere feasible and for all drayage trucks to be zero-emission by 2035.

   c) Strategies, in coordination with other State agencies, U.S. Environmental Protection Agency and local air districts, to achieve 100 percent zero-emission from off-road vehicles and equipment operations in the State by 2035.

   In implementing this Paragraph, the State Air Resources Board shall act consistently with technological feasibility and cost-effectiveness.

3. The Governor's Office of Business and Economic Development, in consultation with the State Air Resources Board, Energy Commission, Public Utilities Commission, State Transportation Agency, the

Department of Finance and other State agencies, local agencies and the private sector, shall develop a Zero-Emissions Vehicle Market Development Strategy by January 31, 2021, and update every three years thereafter, that:

a) Ensures coordinated and expeditious implementation of the system of policies, programs and regulations necessary to achieve the goals and orders established by this Order.

b) Outlines State agencies' actions to support new and used zero-emission vehicle markets for broad accessibility for all Californians.

4. The State Air Resources Board, the Energy Commission, Public Utilities Commission and other relevant State agencies, shall use existing authorities to accelerate deployment of affordable fueling and charging options for zero-emission vehicles, in ways that serve all communities and in particular low-income and disadvantaged communities, consistent with State and federal law.

5. The Energy Commission, in consultation with the State Air Resources Board and the Public Utilities Commission, shall update the biennial statewide assessment of zero-emission vehicle infrastructure required by Assembly Bill 2127 (Chapter 365, Statues of 2018) to support the levels of electric vehicle adoption required by this Order.

6. The State Transportation Agency, the Department of Transportation and the California Transportation Commission, in consultation with the Department of Finance and other State agencies, shall by July 15, 2021 identify near term actions, and investment strategies, to improve clean transportation, sustainable freight and transit options, while continuing a "fix-it-first" approach to our transportation system, including where feasible:

a) Building towards an integrated, statewide rail and transit network, consistent with the California State Rail Plan, to provide seamless, affordable multimodal travel options for all.

b) Supporting bicycle, pedestrian, and micro-mobility options, particularly in low-income and disadvantaged communities in the State, by incorporating safe and accessible infrastructure into projects where appropriate.

c) Supporting light, medium, and heavy duty zero-emission vehicles and infrastructure as part of larger transportation projects, where appropriate.

7. The Labor and Workforce Development Agency and the Office of Planning and Research, in consultation with the Department of Finance and other State agencies, shall develop by July 15, 2021 and expeditiously implement a Just Transition Roadmap, consistent with the recommendations in the "Putting California on the High Road: A Jobs and Climate Action Plan for 2030" report pursuant to Assembly Bill 398 (Chapter 135, Statutes of 2017).

8. To support the transition away from fossil fuels consistent with the goals established in this Order and California's goal to achieve carbon neutrality by no later than 2045, the California Environmental Protection Agency and the California Natural Resources Agency, in consultation with other State, local and federal agencies, shall expedite regulatory processes to repurpose and transition upstream and downstream oil production facilities, while supporting community participation, labor standards, and protection of public health, safety and the environment. The agencies shall report on progress and provide an action plan, including necessary changes in regulations, laws or resources, by July 15, 2021.

9. The State Air Resources Board, in consultation with other State agencies, shall develop and propose strategies to continue the State's current efforts to reduce the carbon intensity of fuels beyond 2030 with consideration of the full life cycle of carbon.

10. The California Environmental Protection Agency and the California Natural Resources Agency, in consultation with the Office of Planning and Research, the Department of Finance, the Governor's Office of Business and Economic Development and other local and federal agencies, shall develop strategies, recommendations and actions by July 15, 2021 to manage and expedite the responsible closure and remediation of former oil extraction sites as the State transitions to a carbon-neutral economy.

11. The Department of Conservation's Geologic Energy Management Division and other relevant State agencies shall strictly enforce bonding requirements and other regulations to ensure oil extraction operators are responsible for the proper closure and remediation of their sites.

12. The Department of Conservation's Geologic Energy Management Division shall:

    a) Propose a significantly strengthened, stringent, science-based health and safety draft rule that protects communities and workers from the impacts of oil extraction activities by December 31, 2020.

    b) Post on its website for public review and consultation a draft rule at least 60 days before submitting to the Office of Administrative Law.

IT IS FURTHER ORDERED that as soon as hereafter possible, the Order be filed in the Office of the Secretary of State and that widespread publicity and notice be given of this Order.

This Order is not intended to, and does not, create any rights or benefits, substantive or procedural, enforceable at law or in equity, against the State of California, its agencies, departments, entities, officers, employees, or any other person.

IN WITNESS WHEREOF I have hereunto set my hand and caused the Great Seal of the State of California to be affixed this 23rd day of September 2020.

GAVIN NEWSOM
Governor of California

ATTEST:

ALEX PADILLA
Secretary of State

Federal Register
Vol. 59, No. 32
Wednesday, February 16, 1994

Presidential Documents

Title 3—

The President

Executive Order 12898 of February 11, 1994

Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered as follows:

Section 1–1. *Implementation.*

1–101. *Agency Responsibilities.* To the greatest extent practicable and permitted by law, and consistent with the principles set forth in the report on the National Performance Review, each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States and its territories and possessions, the District of Columbia, the Commonwealth of Puerto Rico, and the Commonwealth of the Mariana Islands.

1–102. *Creation of an Interagency Working Group on Environmental Justice.* (a) Within 3 months of the date of this order, the Administrator of the Environmental Protection Agency (''Administrator'') or the Administrator's designee shall convene an interagency Federal Working Group on Environmental Justice (''Working Group''). The Working Group shall comprise the heads of the following executive agencies and offices, or their designees: (a) Department of Defense; (b) Department of Health and Human Services; (c) Department of Housing and Urban Development; (d) Department of Labor; (e) Department of Agriculture; (f) Department of Transportation; (g) Department of Justice; (h) Department of the Interior; (i) Department of Commerce; (j) Department of Energy; (k) Environmental Protection Agency; (l) Office of Management and Budget; (m) Office of Science and Technology Policy; (n) Office of the Deputy Assistant to the President for Environmental Policy; (o) Office of the Assistant to the President for Domestic Policy; (p) National Economic Council; (q) Council of Economic Advisers; and (r) such other Government officials as the President may designate. The Working Group shall report to the President through the Deputy Assistant to the President for Environmental Policy and the Assistant to the President for Domestic Policy.

(b) The Working Group shall: (1) provide guidance to Federal agencies on criteria for identifying disproportionately high and adverse human health or environmental effects on minority populations and low-income populations;

(2) coordinate with, provide guidance to, and serve as a clearinghouse for, each Federal agency as it develops an environmental justice strategy as required by section 1–103 of this order, in order to ensure that the administration, interpretation and enforcement of programs, activities and policies are undertaken in a consistent manner;

(3) assist in coordinating research by, and stimulating cooperation among, the Environmental Protection Agency, the Department of Health and Human Services, the Department of Housing and Urban Development, and other agencies conducting research or other activities in accordance with section 3–3 of this order;

(4) assist in coordinating data collection, required by this order;

(5) examine existing data and studies on environmental justice;

(6) hold public meetings as required in section 5–502(d) of this order; and

(7) develop interagency model projects on environmental justice that evidence cooperation among Federal agencies.

1–103. *Development of Agency Strategies.* (a) Except as provided in section 6–605 of this order, each Federal agency shall develop an agency-wide environmental justice strategy, as set forth in subsections (b)–(e) of this section that identifies and addresses disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations. The environmental justice strategy shall list programs, policies, planning and public participation processes, enforcement, and/or rulemakings related to human health or the environment that should be revised to, at a minimum: (1) promote enforcement of all health and environmental statutes in areas with minority populations and low-income populations; (2) ensure greater public participation; (3) improve research and data collection relating to the health of and environment of minority populations and low-income populations; and (4) identify differential patterns of consumption of natural resources among minority populations and low-income populations. In addition, the environmental justice strategy shall include, where appropriate, a timetable for undertaking identified revisions and consideration of economic and social implications of the revisions.

(b) Within 4 months of the date of this order, each Federal agency shall identify an internal administrative process for developing its environmental justice strategy, and shall inform the Working Group of the process.

(c) Within 6 months of the date of this order, each Federal agency shall provide the Working Group with an outline of its proposed environmental justice strategy.

(d) Within 10 months of the date of this order, each Federal agency shall provide the Working Group with its proposed environmental justice strategy.

(e) Within 12 months of the date of this order, each Federal agency shall finalize its environmental justice strategy and provide a copy and written description of its strategy to the Working Group. During the 12 month period from the date of this order, each Federal agency, as part of its environmental justice strategy, shall identify several specific projects that can be promptly undertaken to address particular concerns identified during the development of the proposed environmental justice strategy, and a schedule for implementing those projects.

(f) Within 24 months of the date of this order, each Federal agency shall report to the Working Group on its progress in implementing its agency-wide environmental justice strategy.

(g) Federal agencies shall provide additional periodic reports to the Working Group as requested by the Working Group.

1–104. *Reports to the President.* Within 14 months of the date of this order, the Working Group shall submit to the President, through the Office of the Deputy Assistant to the President for Environmental Policy and the Office of the Assistant to the President for Domestic Policy, a report that describes the implementation of this order, and includes the final environmental justice strategies described in section 1–103(e) of this order.

Sec. 2–2. *Federal Agency Responsibilities for Federal Programs.* Each Federal agency shall conduct its programs, policies, and activities that substantially affect human health or the environment, in a manner that ensures that such programs, policies, and activities do not have the effect of excluding persons (including populations) from participation in, denying persons (including populations) the benefits of, or subjecting persons (including populations) to discrimination under, such programs, policies, and activities, because of their race, color, or national origin.

Sec. 3–3. *Research, Data Collection, and Analysis.*

3–301. *Human Health and Environmental Research and Analysis.* (a) Environmental human health research, whenever practicable and appropriate, shall include diverse segments of the population in epidemiological and clinical studies, including segments at high risk from environmental hazards, such as minority populations, low-income populations and workers who may be exposed to substantial environmental hazards.

(b) Environmental human health analyses, whenever practicable and appropriate, shall identify multiple and cumulative exposures.

(c) Federal agencies shall provide minority populations and low-income populations the opportunity to comment on the development and design of research strategies undertaken pursuant to this order.

3–302. *Human Health and Environmental Data Collection and Analysis.* To the extent permitted by existing law, including the Privacy Act, as amended (5 U.S.C. section 552a): (a) each Federal agency, whenever practicable and appropriate, shall collect, maintain, and analyze information assessing and comparing environmental and human health risks borne by populations identified by race, national origin, or income. To the extent practical and appropriate, Federal agencies shall use this information to determine whether their programs, policies, and activities have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations;

(b) In connection with the development and implementation of agency strategies in section 1–103 of this order, each Federal agency, whenever practicable and appropriate, shall collect, maintain and analyze information on the race, national origin, income level, and other readily accessible and appropriate information for areas surrounding facilities or sites expected to have a substantial environmental, human health, or economic effect on the surrounding populations, when such facilities or sites become the subject of a substantial Federal environmental administrative or judicial action. Such information shall be made available to the public, unless prohibited by law; and

(c) Each Federal agency, whenever practicable and appropriate, shall collect, maintain, and analyze information on the race, national origin, income level, and other readily accessible and appropriate information for areas surrounding Federal facilities that are: (1) subject to the reporting requirements under the Emergency Planning and Community Right-to-Know Act, 42 U.S.C. section 11001–11050 as mandated in Executive Order No. 12856; and (2) expected to have a substantial environmental, human health, or economic effect on surrounding populations. Such information shall be made available to the public, unless prohibited by law.

(d) In carrying out the responsibilities in this section, each Federal agency, whenever practicable and appropriate, shall share information and eliminate unnecessary duplication of efforts through the use of existing data systems and cooperative agreements among Federal agencies and with State, local, and tribal governments.

Sec. 4–4. *Subsistence Consumption of Fish and Wildlife.*

4–401. *Consumption Patterns.* In order to assist in identifying the need for ensuring protection of populations with differential patterns of subsistence consumption of fish and wildlife, Federal agencies, whenever practicable and appropriate, shall collect, maintain, and analyze information on the consumption patterns of populations who principally rely on fish and/or wildlife for subsistence. Federal agencies shall communicate to the public the risks of those consumption patterns.

4–402. *Guidance.* Federal agencies, whenever practicable and appropriate, shall work in a coordinated manner to publish guidance reflecting the latest scientific information available concerning methods for evaluating the human health risks associated with the consumption of pollutant-bearing fish or wildlife. Agencies shall consider such guidance in developing their policies and rules.

Sec. 5–5. *Public Participation and Access to Information.* (a) The public may submit recommendations to Federal agencies relating to the incorporation of environmental justice principles into Federal agency programs or policies. Each Federal agency shall convey such recommendations to the Working Group.

(b) Each Federal agency may, whenever practicable and appropriate, translate crucial public documents, notices, and hearings relating to human health or the environment for limited English speaking populations.

(c) Each Federal agency shall work to ensure that public documents, notices, and hearings relating to human health or the environment are concise, understandable, and readily accessible to the public.

(d) The Working Group shall hold public meetings, as appropriate, for the purpose of fact-finding, receiving public comments, and conducting inquiries concerning environmental justice. The Working Group shall prepare for public review a summary of the comments and recommendations discussed at the public meetings.

Sec. 6–6. *General Provisions.*

6–601. *Responsibility for Agency Implementation.* The head of each Federal agency shall be responsible for ensuring compliance with this order. Each Federal agency shall conduct internal reviews and take such other steps as may be necessary to monitor compliance with this order.

6–602. *Executive Order No. 12250.* This Executive order is intended to supplement but not supersede Executive Order No. 12250, which requires consistent and effective implementation of various laws prohibiting discriminatory practices in programs receiving Federal financial assistance. Nothing herein shall limit the effect or mandate of Executive Order No. 12250.

6–603. *Executive Order No. 12875.* This Executive order is not intended to limit the effect or mandate of Executive Order No. 12875.

6–604. *Scope.* For purposes of this order, Federal agency means any agency on the Working Group, and such other agencies as may be designated by the President, that conducts any Federal program or activity that substantially affects human health or the environment. Independent agencies are requested to comply with the provisions of this order.

6–605. *Petitions for Exemptions.* The head of a Federal agency may petition the President for an exemption from the requirements of this order on the grounds that all or some of the petitioning agency's programs or activities should not be subject to the requirements of this order.

6–606. *Native American Programs.* Each Federal agency responsibility set forth under this order shall apply equally to Native American programs. In addition, the Department of the Interior, in coordination with the Working Group, and, after consultation with tribal leaders, shall coordinate steps to be taken pursuant to this order that address Federally-recognized Indian Tribes.

6–607. *Costs.* Unless otherwise provided by law, Federal agencies shall assume the financial costs of complying with this order.

6–608. *General.* Federal agencies shall implement this order consistent with, and to the extent permitted by, existing law.

6–609. *Judicial Review.* This order is intended only to improve the internal management of the executive branch and is not intended to, nor does it create any right, benefit, or trust responsibility, substantive or procedural, enforceable at law or equity by a party against the United States, its agencies, its officers, or any person. This order shall not be construed to create any right to judicial review involving the compliance or noncompliance of the United States, its agencies, its officers, or any other person with this order.

THE WHITE HOUSE,
February 11, 1994.

[FR Citation 59 FR 7629]

LEGAL STATUS

Federal Implementation Plan Addressing Reasonably Available Control Technology Requirements for Certain Sources in Pennsylvania

A Rule by the Environmental Protection Agency on 08/31/2022

DOCUMENT DETAILS

Printed version:
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This final rule is effective on September 30, 2022.

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40 CFR 52

Agency/Docket Numbers:
EPA-R03-OAR-2022-0347
FRL-9333-02-R3

Document Number:

AGENCY:

Environmental Protection Agency (EPA).

ACTION:

Final rule.

SUMMARY:

The Environmental Protection Agency (EPA) is promulgating a Federal implementation plan (FIP) for the Commonwealth of Pennsylvania (Pennsylvania or the Commonwealth). This FIP sets emission limits for nitrogen oxides (NO_X) emitted from coal-fired electric generating units (EGUs) equipped with selective catalytic reduction (SCR) in Pennsylvania in order to meet the reasonably available control technology (RACT) requirements for the 1997 and 2008 ozone national ambient air quality standards (NAAQS). This action is being taken in accordance with the requirements of the Clean Air Act (CAA).

DATES:

This final rule is effective on September 30, 2022.

ADDRESSES:

EPA has established a docket for this action under Docket ID Number EPA-R03-OAR-2022-0347. All documents in the docket are listed on the *www.regulations.gov (http://www.regulations.gov)* website. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available through *www.regulations.gov (http://www.regulations.gov),* or please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section for additional availability information.

FOR FURTHER INFORMATION CONTACT:

David Talley, Permits Branch (3AD10), Air & Radiation Division, U.S. Environmental Protection Agency, Region III, Four Penn Center, 1600 John F. Kennedy Boulevard, Philadelphia, Pennsylvania 19103. The telephone number is (215) 814-2117. Mr. Talley can also be reached via electronic mail at *talley.david@epa.gov (mailto:talley.david@epa.gov).*

SUPPLEMENTARY INFORMATION:

I. Background

On May 25, 2022 (87 FR 31798 (/citation/87-FR-31798)), EPA published a notice of proposed rulemaking (NPRM) addressing NO_X emissions from coal-fired power plants in the Commonwealth of Pennsylvania. In the NPRM, EPA proposed a FIP in order to address the CAA's RACT requirements under the 1997 and 2008 ozone NAAQS for large, coal-fired EGUs equipped with SCR in Pennsylvania. As discussed in the NPRM, the FIP was proposed as an outgrowth of a decision by the United States Court of Appeals for the Third Circuit ("the Court"), which vacated and remanded to EPA a portion of our prior approval of Pennsylvania's "RACT II" rule which applied to the same universe of sources. See 87 FR 31798 (/citation/87-FR-31798); 31799-39802.

The Court directed that "[o]n remand, the agency must either approve a revised, compliant SIP within two years or formulate a new Federal implementation plan." *Sierra Club* v. *EPA,* 972 F.3d 290, 309 (3rd Circuit 2020) ("Sierra Club"). On September 15, 2021, EPA proposed disapproval of those portions of the prior approval which were vacated by the Court. See 86 FR 51315 (/citation/86-FR-51315). EPA took final action to disapprove the vacated portions of our prior approval. 87 FR 50257 (/citation/87-FR-50257), August 16, 2022. EPA is now finalizing a FIP to fulfill the Court's order.

The collection of sources addressed by the RACT analysis in this FIP has been determined by the scope of the Third Circuit's order in the Sierra Club case and EPA's subsequent disapproval action. Herein, EPA is finalizing RACT control requirements for the four facilities that remain open and active that were subject to the SIP provision that the Court vacated EPA's approval of and that EPA thereafter disapproved: Conemaugh, Homer City, Keystone, and Montour. EPA's prior approval action and the Court's decision related to source-specific RACT determinations for the Cheswick, Conemaugh, Homer City, Keystone, and Montour generating stations. The Bruce Mansfield and Cheswick facilities ceased operation, so there is no longer a need to address RACT requirements for those facilities, so are not at included in this final action. Accordingly, there are a total of nine affected EGUs/units at four facilities in this action: three at Homer City and two each at Conemaugh, Keystone and Montour.

The Pennsylvania Department of Environmental Protection (PADEP) undertook efforts to develop a SIP revision addressing the deficiencies identified by the Third Circuit in the *Sierra Club* decision. PADEP proceeded to develop source specific ("case-by-case") RACT determinations for the generating stations at issue. By April 1, 2021, each of the facilities had submitted permit applications to PADEP with alternative RACT proposals in accordance with 25 Pa. Code 129.99. Subsequently, PADEP issued technical deficiency notices to obtain more information needed to support the facilities' proposed RACT determinations. Although additional information was provided in response to these notices, PADEP determined the proposals to be insufficient and began developing its own RACT determination for each facility. The outcome of this process was PADEP's issuance of draft permits for each facility, which were developed with the intention of submitting each case-by-case RACT permit to be incorporated as a federally enforceable revision to the Pennsylvania SIP. Each draft permit underwent a 30-day public comment period,[1] during which EPA provided source-specific comments to PADEP for each permit. On May 26, 2022, PADEP submitted case-by-case RACT determinations for Keystone, Conemaugh, and Homer City as a revision to the Pennsylvania SIP. On June 9, 2022, PADEP submitted a case-by-case RACT determination for Montour as a revision to the Pennsylvania SIP. EPA has not yet fully evaluated those submittals and they are outside of the scope of this action. Any action on those proposed SIP revisions will be at a later date and under a separate action.

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II. Summary of FIP and EPA Analysis

A. Overall Basis for Final Rule

This section presents a summary of the basis for the final FIP. The overall basis for the proposal was explained in detail in the NPRM. The overall basis is largely unchanged from proposal, though as explained in the responses to comments and section IV of this document on the final limits, some adjustments were made to the resulting limits. For more detail on what was proposed, please refer to the May 25, 2022 proposal publication (87 FR 31798 (/citation/87-FR-31798)).

The basis for the final rule begins with the RACT definition. As discussed in the NPRM, RACT is not defined in the CAA. However, EPA's longstanding definition of RACT is "the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." [2] The Third Circuit decision "assume[d] without deciding" that EPA's definition of RACT is correct. *Sierra Club* at 294. EPA is using its longstanding definition of RACT to establish the limits in this FIP.

The EPA proposed that RACT limits in this FIP will apply throughout the year. As discussed further in Section III of this preamble in response to comments on this issue, the EPA is retaining year-round limits because the limits herein are technologically and economically feasible during the entire year. While other regulatory controls for ozone, such as the Cross State Air Pollution Rule (CSAPR) and its updates, may apply during a defined ozone season, the RACT limits finalized herein do not authorize seasonal exemptions based on atmospheric conditions or other factors. As explained, this action is being finalized to meet the statutory requirement to implement RACT in accordance with sections 182 and 184 of the Clean Air Act. Implementation of RACT, and the definition of what is RACT, is not constrained by the ozone season or atmospheric consideration. Therefore, the limits finalized here apply throughout the year since the RACT emissions rates are technologically and economically feasible year-round. To the degree that the EPA analyses underlying the RACT emissions limits here rely on past performance data, those calculations typically use ozone season data. This is because ozone season data generally represent the time period over which the NO_X emissions rate performance of these units is the best. Put another way, the ozone season data for the facilities subject to these limits are a reliable indicator of what is technologically and economically feasible for these facilities, and EPA has no reason to believe that achieving the same performance outside the ozone season would be technologically or economically infeasible. As explained further in the next section, no commenters presented compelling evidence to change EPA's conclusion on this point.

The EPA proposed to develop the FIP limits using a weighted rate approach, and is retaining that overall approach here. EPA received significant comments both for and against such an approach, which are discussed in detail in the next section. Overall, upon consideration of these comments, the EPA's judgment is that this approach is still the best approach for addressing the Court decision and addressing SCR operation during EGU cycling (the operation of EGUs turning on and off or operating at varying loads levels based on electric demand). As we discussed extensively at proposal, the cycling of units, combined with the role of flue gas temperature in SCR performance, prompted EPA to consider how best to establish RACT limits that address the Third Circuit's concerns about allowing less stringent limits when flue gas temperatures went below what it considered to be an arbitrary temperature threshold. This is a challenging factor to consider in cases when the operating temperature varies, and when the units spend some time at temperatures where SCR is very effective, and some time at temperatures where it is not.

At proposal, EPA provided an assessment of whether the units in this FIP exhibit a pattern of cycling between temperatures where SCR is effective and where it is not. EPA evaluated years of data submitted by these sources to EPA to characterize their variability in hours of operation or level of operation.[3] In particular, EPA used this information to identify whether, or to what degree, the EGUs have shifted from being "baseload" units (*i.e.,* a steady-state heat input rate generally within SCR optimal temperature range) to "cycling" units (*i.e.,* variable heat input rates, possibly including periods below the SCR optimal temperature range). All of these EGUs were designed and built as baseload units, meaning the boilers were designed to be operated at levels of heat input near their design capacity 24 hours per day, seven days per week, for much of the year. As a result, the SCRs installed in the early 2000s were designed and built to work in tandem with a baseload boiler.[4] In particular, the SCR catalyst and the reagent injection controls were designed for the consistently higher flue gas temperatures created by baseload boiler operation. In more recent years, for multiple reasons, these old, coal-fired baseload units have struggled to remain competitive when bidding into the PJM Interconnection (PJM) electricity market.[5] Nationally, total electric generation has generally remained consistent, but between 2010 and 2020, generation at coal-fired utilities has declined by 68%.[6] As a result, many of these units more recently have tended to cycle between high heat inputs, when electricity demand is high, and lower heat inputs or complete shutdowns, when demand is low, sometimes on a daily basis. This cycling behavior can affect the ability of the EGUs to operate their SCRs because at lower heat inputs the temperature of the flue gas can drop below the operating temperature for which the SCR was designed.[7] Nothing in the comments undermined EPA's basic conclusion that this cycling pattern is occurring. Accordingly, the final rule establishes limits that account for the technical limits on SCR operation that can result from this cycling behavior.

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In the proposal, we also noted that in RACT II, PADEP attempted to address this cycling behavior by creating tiered emissions limits for different modes of operation based on the flue gas temperature, which its RACT II rule expressed as a transition from the 0.12 pounds of NO_X per million British thermal units (lb/MMBtu) rate to much less stringent rates (between 0.35 and 0.4 lb/MMBtu, depending on the type of boiler) based on a temperature cutoff of 600 degrees, with the less stringent rate essentially representing a "SCR-off" mode (

i.e., an emission limit applicable at times when the SCR has been idled or bypassed and is not actively removing NO_X). The Third Circuit rejected this approach because the selection of the cutoff temperature was not sufficiently supported by the record. The Third Circuit decision also questioned the need for the less stringent rates, noting that nearby states do not have different emission rates based on inlet temperatures. EPA considered the Court's concerns as well as input received during the public comment period expressing both support for, and opposition to, a tiered limit. We also considered the practical and policy implications in structuring a tiered limit for these cycling EGUs based on operating temperature. EPA has decided to retain the proposed weighted approach instead of trying to develop a tiered limit. As noted at proposal, the effectiveness of SCR does not drop to zero at a single temperature point and defining the minimum reasonable temperature range to begin reducing SCR operation for the purposes of creating an enforceable RACT limit is a highly technical, unit-specific determination that depends on several varying factors.[8] We noted the complexity and detailed information necessary to produce a justified and enforceable tiered limit that represents RACT and addresses the Court's concerns about the basis and enforceability of the tiers, and as explained further in the next section, none of the comments, including those supporting the tiered limit, provided sufficient basis for EPA to change its approach.

In the proposal, EPA expressed an additional concern about addressing cycling operation through a tiered RACT limit based on operating temperature, which is that it would create an incentive for a source to cycle to temperatures where SCR is not required, in order to avoid SCR operating costs and potentially gain a competitive advantage. In the case of the Pennsylvania limits addressed by the Third Circuit's decision, there was no limit on how much time the units could spend in SCR-off mode. In section C of the TSD for the proposed action,[9] EPA shows that over the last decade, some affected sources have varied the gross load level to which they cycle down, hovering either just above or just below the threshold at which the SCR can likely operate effectively. Depending on the unit, this slight change in electricity output could significantly affect SCR operation and the resulting emissions output. Though instances of cycling below SCR thresholds occurred in some cases prior to the implementation of Pennsylvania's tiered RACT limit and thus the limit may not be the sole driver of the behavior following its implementation, the tiered limit certainly allows this behavior to occur. While EPA acknowledges the need for EGUs to operate at times in modes where SCR cannot operate, EPA believes its RACT limit should minimize incentives to do that, and a tiered rate structure that effectively has no limit on SCR-off operation tends to do the opposite. We received significant comments on this concern, which are addressed in the response to comments section. EPA remains concerned about essentially unlimited SCR-off operation, and continues to believe that this is a key reason to retain the weighted rate approach over a tiered approach.

On the other hand, EPA also expressed concerns in the proposal about a RACT limit that treats these EGUs as always operating as baseload units by imposing a NO_X emission rate that applies at all times but can technically be achieved only if the boiler is operating at high loads. Recent data indicate that these units are not operating as baseload units and are not likely to do so in the future.[10] Selecting the best baseload rate (the rate reflecting SCR operation in the optimal temperature range) and applying that rate at all times does not account for, and could essentially prohibit, some cycling operation of these units. Cycling has become more common at coal-fired EGUs because they are increasingly outcompeted for baseload power. In the past, these units were among the cheapest sources of electricity and would often run close to maximum capacity. Other EGUs can now generate electricity at lower costs than the coal-fired units.[11] Thus, the coal-fired units now cycle to lower loads during hours with relatively low system demand (often overnight and especially during the spring and fall “shoulder” seasons when space heating and cooling demand is minimized) when their power is more expensive than the marginal supply to meet lower load levels. Hence, they cycle up and down as load- and demand-driven power prices rise and fall, and they operate when the price meets or exceeds their cost to supply power. EPA acknowledges that cycling down to a SCR-off mode may sometimes happen, for example, when electricity demand drops unexpectedly, and other units provide the power at a lower cost. The consideration of the technical and economic feasibility of a given RACT limit should reflect, to the extent possible, consideration of the past, current, and future expected operating environment of a given unit. In electing to finalize its weighted rate approach, EPA considered these feasibility issues to establish a rate for each unit that reflects a reasonable level of load-following (cycling) (*e.g.,* a level consistent with similar SCR-equipped units) but that also accounts for the lower historic NO_X rates that these units have achieved. While the comments generally affirmed that a weighted rate could be structured to address cycling, we did receive comments on the appropriate considerations in choosing the final rates, which are responded to later in this notice.

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B. Weighted Rates

As discussed in the NPRM, in order to address the concerns discussed previously in this section about how to determine RACT for EGUs that cycle, EPA proposed to express the RACT NO_X limits for these units using a weighted rate limit. The weighted rate incorporates both a lower "SCR-on" limit and a higher "SCR-off" limit. Through assignment of weights to these two limits based on the proportion of operation in SCR-on and SCR-off modes during a historical period that encompasses the range of recent operation, the SCR-on and SCR-off limits are combined into a single RACT limit that applies at all times. The weight given to the proposed SCR-off limit (established as described later in this section) has the effect of limiting the portion of time a cycling source can operate in SCR-off mode and incentivizes a source to shift to SCR-on mode to preserve headroom under the limit. While driving SCR operation, the weighted limit accommodates the need for an EGU to occasionally cycle down to loads below which the SCR can operate effectively and does not prohibit SCR-off operation or dictate specific times when it must not occur. In this way, this approach avoids the difficulty of precisely establishing the minimum temperature point at which the SCR-off mode is triggered, effectively acknowledging the more gradual nature of the transition between modes where SCR is or is not effective. Finally, it is readily enforceable through existing Continuous Emission Monitoring Systems (CEMS), without the need for development of recordkeeping for additional parameters that define the SCR-off mode. The approach is described in more detail below.

As a starting point for developing the proposed weighted rates for each unit, EPA examined data related to the threshold at which these facilities can effectively operate their SCR. Then, EPA calculated both SCR-on and SCR-off rates using historic ozone season operating data for the unit to determine when the SCR was likely running and when it was likely not running, and then established rates based again on historic operating data that represent the lowest emission limit that the source is capable of meeting when the SCR is running and when it is not. EPA did this by using the estimated minimum SCR operation threshold as described in the proposed action, and then calculating average SCR-on and SCR-off rates for each unit based on historic ozone season operating data for that unit, when available, from 2003 to 2021. For more detail on the development of the proposed rates, see section D of the TSD for the proposed action. In particular, section D.1 addresses the proposed threshold analysis. The SCR-on rate is an average of all hours in which the SCR was likely running (operating above the threshold at which it can run the SCR with an hourly NO_X emission rate below 0.2 lb/MMBtu) during each unit's third-best ozone season from the period 2003 to 2021. The third-best ozone season was identified based on the unit's overall average NO_X emission rate during each ozone season from 2003 to 2021. This time period captures all years of SCR operation for each facility, though Conemaugh only installed SCR in late 2014. EPA included all these years of data in developing the proposed as well as the final limits because the Agency did not identify, and commenters did not provide, a compelling reason to exclude any of the years. This is in line with the Third Circuit's decision, which questioned EPA's review of only certain years of emissions data for these sources in determining whether to approve Pennsylvania's RACT II NO_X emission rate for these EGUs. The use of the third-best year accounts for degradation of control equipment over time, and it avoids biasing the limit with uncharacteristically low emitting days, or under uncharacteristically optimal operating conditions. EPA similarly used a third-best ozone season approach for the Revised CSAPR Update (86 FR 23054 (/citation/86-FR-23054), April 30, 2021) (RCU) and the proposed Good Neighbor Plan for the 2015 Ozone NAAQS (87 FR 20036 (/citation/87-FR-20036), April 6, 2022) (Good Neighbor Plan). The “SCR-off” rate used to develop the proposal is an average of all hours in which the unit's SCR was likely not running (operating below the threshold at which it can run the SCR with an hourly NO_X rate above 0.2 lb/MMBtu) during all ozone seasons from 2003-2021 (except for Conemaugh). All ozone seasons in the time period were used in order to increase the sample size of this subset of the data, as an individual ozone season likely contains significantly fewer data points of non-SCR operation.

EPA then calculated the SCR-on and SCR-off “weights,” which represent the amount of heat input spent above (SCR-on) or below (SCR-off) the SCR threshold, for each EGU. For the weights used at the proposal stage, EPA evaluated data from the 2011 to 2021 ozone seasons and selected the year in which the EGU had its third highest proportion of heat input spent above the SCR threshold during this time period, using that year's weight (the “third-best weight”) together with the SCR-on/SCR-off rates described previously to calculate the weighted rate. The years 2011-2021 were analyzed for purposes of the proposal because they likely are representative of the time period that encompasses the years when the units began to exhibit a greater cycling pattern, and it is reasonable to expect that this pattern will continue for the foreseeable future.

Using these data, EPA proposed emissions limitations based on the following equation:

> *(SCR-on weight * SCR-on mean rate) + (SCR off weight * SCR off mean rate)* = emissions limit in lb/MMBtu.

Using this equation, EPA proposed the NO_X emission limits listed in Table 1, based on a 30-day rolling average:

Table 1—Proposed NO_X Emission Rate Limits[12]

Facility name	Unit	Low range rate (lb/MMBtu)	High range rate (lb/MMBtu)	Weighted rate (lb/MMBtu)	Proposed facility-wide 30-day average rate limit (lb/MMBtu)
Cheswick	1	0.085	0.195	0.099	0.099
Conemaugh	1	0.071	0.132	0.091	0.091
Conemaugh	2	0.070	0.132	0.094	
Homer City	1	0.102	0.190	0.102	0.088
Homer City	2	0.088	0.126	0.088	
Homer City	3	0.096	0.136	0.097	
Keystone	1	0.046	0.170	0.076	0.074
Keystone	2	0.045	0.172	0.074	
Montour	1	0.047	0.131	0.069	0.069
Montour	2	0.048	0.145	0.070	

EPA solicited comment on the proposed facility-wide average rate limits, as well as the low and high range of potential limits. The limits are calculated as a 30-day rolling average, and apply at all times, including during operations when exhaust gas temperatures at the SCR inlet are too low for the SCR to operate, or operate optimally. For facilities with more than one unit, EPA proposed to allow facility-wide averaging for compliance, but proposed that the average limit be based on the weighted rate achieved by the best performing unit. A 30-day average "smooths" operational variability by averaging the current value with the prior values over a rolling 30-day period to determine compliance. While some period of lb/MMBtu values over the compliance rate can occur without triggering a violation, they must be offset by corresponding periods where the lb/MMBtu rate is lower than the compliance rate (*i.e.,* the 30-day rolling average rate). EPA is retaining its proposed overall approach to developing these limits, but for reasons discussed in Section III of this preamble, EPA is changing the way the rate calculation is done for facilities with more than one unit, and is making additional adjustments to the rate calculation in response to technical information received. These changes result in some changes to the final rates, which are discussed in section IV of this preamble.

C. Daily NO_X Mass Emission Rates

EPA also proposed a unit-specific daily NO_X mass emission limit (*i.e.,* lb/day) to complement the weighted facility-wide 30-day NO_X emission rate limit and further ensure RACT is applied continuously. High emissions days are a concern, given the 8-hour averaging time of the underlying 1997 and 2008 ozone NAAQS. The proposed daily NO_X mass emission limit was calculated by multiplying the proposed facility-wide 30-day rolling average NO_X emission limit (in lb/MMBtu) by each unit's heat input maximum permitted rate capacity (in MMBtu/hr) by 24 hours. While the 30-day average rate limit ensures that SCR is operated where feasible while reasonably accounting for cycling, EPA is concerned that units meeting this limit might still occasionally have higher daily mass emissions on one or more days where no or limited SCR operation occurs, which could trigger exceedances of the ozone NAAQS if these high mass emissions occur on days conducive to ozone formation, such as especially hot summer days. EPA proposed a daily mass limit that would govern over a full 24-hr, calendar day basis as an additional constraint on SCR-off operation within a single day. The proposed limit was designed to provide for some boiler operation without using the SCR, which may be unavoidable during part of any given day, but also to constrain such operation because the mass limit will necessitate SCR operation (for example by raising heat input to a level where the SCR can operate) if the unit is to continue to operate while remaining below this limit. This provides greater consistency with the RACT definition. Table 2 shows the unit-specific daily NO_X mass limits that were proposed in the NPRM.

Table 2—Proposed Daily NO_X Mass Limits [13]

Cheswick	1	6,000	14,256
Conemaugh	1	8,280	18,084
Conemaugh	2	8,280	18,084
Homer City	1	6,792	14,345
Homer City	2	6,792	14,345
Homer City	3	7,260	15,333
Keystone	1	8,717	15,481

Facility name	Unit	Permitted max hourly heat input rate (MMBtu/hr) [14]	Proposed unit-specific mass limit (lb/day)
Keystone	2	8,717	15,481
Montour	1	7,317	12,117
Montour	2	7,239	11,988

EPA solicited comment on the proposed daily mass limits. As discussed in more detail in section III of this preamble, EPA considered the comments received and made some changes to the final limits. The final limits are discussed in section IV of this preamble.

III. EPA's Response to Comments Received

EPA received 10 sets of comments on our May 25, 2022 proposed FIP. A summary of the comments and EPA's response is provided herein. All comments received are included in the docket for this action.

Comment: Allegheny County Health Department (ACHD) submitted a comment clarifying the operating status of the Cheswick Generating Station.

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Facility name | Unit | Permitted max hourly heat input rate (MMBtu/hr) [14] | Proposed unit-specific mass limit (lb/day)

Response: EPA acknowledges the comment provided by ACHD. In our NPRM, EPA described Cheswick as being in the process of closing, despite ACHD having issued a title V permit modification that included a provision requiring Boiler #1 to cease operations on April 1, 2022. While that deadline had come and gone by the time the NPRM was published, it was not entirely clear at the time of drafting the notice that the closure was permanent and enforceable. ACHD's comment addressed EPA's characterization of Cheswick's status in the NPRM and affirmed that ACHD has verified that Cheswick's main boiler and associated equipment have been permanently shut down. In the intervening months since the NPRM, EPA has confirmed, with assistance from ACHD, that the boiler has in fact ceased operating, and that Cheswick's title V operating permit has been terminated. Therefore, EPA finds that the closure is permanent and enforceable, and as such, is not finalizing any RACT limits for Cheswick as proposed in our NPRM.

Comment: Commenters assert that EPA must take action on PADEP's May 26, 2022 and June 9, 2022 SIP submittals, which included Pennsylvania's own source specific RACT determinations, and which were intended to address the deficiencies identified by the Third Circuit, prior to (or concurrently with) promulgating a FIP.

Response: Although EPA generally pursues a "state first" approach to air quality management, giving deference to states to determine the best strategy for addressing air quality concerns within their boundaries in the first instance, EPA does not agree with the commenters' assertion that EPA must act on PADEP's RACT SIP submittals prior to or concurrently with finalizing a FIP. On September 15, 2021, EPA proposed to disapprove those portions of Pennsylvania's May 16, 2016 SIP upon which EPA's prior approval had been vacated and remanded by the Third Circuit, and that are encompassed in this FIP action. 86 FR 51315 (/citation/86-FR-51315). EPA recently finalized that disapproval. 87 FR 50257 (/citation/87-FR-50257). CAA section 110(c)(1)(B) requires the Administrator to "promulgate a Federal implementation plan *at any time* within 2 years after the Administrator disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency *and the Administrator approves* the plan or plan revision, before the Administrator promulgates such Federal implementation plan" (emphasis added). Following EPA's August 16, 2022 (87 FR 50257 (/citation/87-FR-50257)) final disapproval, EPA has authority to promulgate a FIP under CAA section 110(c) at any time because EPA has not approved a plan or plan revision from Pennsylvania correcting the deficiency. Nothing in the Clean Air Act requires EPA to act upon a SIP submitted by a state to address a deficiency identified in EPA's final disapproval prior to promulgating a FIP, and the commenters have not provided any statutory basis for such a position.

As explained in the NPRM for this action, EPA may promulgate a FIP contemporaneously with or immediately following the predicate final disapproval action on a SIP (or finding that no SIP was submitted). *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489, 509 (2014) ("EPA is not obliged to wait two years or postpone its action even a single day: The Act empowers the Agency to promulgate a FIP `at any time' within the two-year limit") (internal citations omitted). In order to provide for this, it cannot be true that EPA must take further action on SIP submittals from the state prior to undertaking rulemaking for a FIP. The practical effect of applying the procedure commenters allege, that EPA must consider a new SIP submittal from the state prior to promulgating a FIP, would be that EPA would either approve the state's new SIP revision (thereby nullifying the need for a FIP) or EPA would disapprove the state's new SIP revision, which would essentially require a double disapproval from EPA in such circumstances. This cannot be understood to be Congress's intent. When considering a similar question, the Federal Court of Appeals for the Tenth Circuit agreed with the interpretation EPA here states. Specifically, the Tenth Circuit stated: "The statute itself makes clear that the mere *filing* of a SIP by Oklahoma does not relieve the EPA of its duty. And the petitioners do not point to any language that requires the EPA to delay its promulgation of a FIP until it rules on a proposed SIP. As the EPA points out, such a rule would essentially nullify any time limits the EPA placed on states. States could forestall the promulgation of a FIP by submitting one inadequate SIP after another." *Oklahoma* v. *EPA,* 723 F.3d 1201, 1223 (10th Cir. 2013) (emphasis in original).

EPA has not fully evaluated Pennsylvania's May 26 and June 9, 2022 submittals and has not yet proposed action on the SIP submittals. As explained, this does not alter EPA's authority to finalize this action promulgating a FIP. EPA intends to evaluate and take action on Pennsylvania's submittal in accordance with the timelines established in CAA section 110(k)(2). However, as noted in the NPRM, EPA submitted extensive comments on the draft permits. In those comments, EPA raised several concerns that remain unresolved, including whether Pennsylvania's continued use of tiered limits (*i.e.,* separate limits for SCR-on and SCR-off operation) could be squared with the Court's clear objection to our approval of such an approach in the past, and whether Pennsylvania's record was adequate to support the limits selected, the need for separate limits, and how to determine when each limit applied.

Comment: Several commenters asserted that EPA erred in the selection of SCR as RACT. PADEP asserts that EPA's proposal does not provide a source specific analysis of technological feasibility for each unit, and that it does not identify any specific control technology or technique as being technically feasible. They claim that EPA's approach fails to comport with previous RACT approaches. Keystone/Conemaugh (Key-Con) suggests that EPA overlooked the technical and economic circumstances of the individual sources in determining RACT. Additionally, one commenter, Talen Energy, alleged that EPA should have selected feasible controls that "represent RACT for each mode of operation of the units, such as startup and shutdown."

Response: EPA disagrees with those comments suggesting that EPA's FIP proposal did not follow the long-standing definition of RACT. Courts have repeatedly concluded that the term "reasonably available" is ambiguous and therefore the statute does not specify which emission controls must be considered "reasonably available." *See, e.g., Natural Resources Defense Council* v. *EPA,* 571 F.3d 1245, 1252 (D.C. Cir. 2009) (stating "the term `reasonably available' within RACT is also ambiguous" and "[g]iven this ambiguity, the EPA has discretion reasonably to define the controls that will demonstrate compliance"). *See also, Sierra Club* v. *EPA,* 294 F.3d 155, 162-63 (D.C. Cir. 2002) (finding that the term "reasonably available" in the analogous “reasonably available control measure” is ambiguous and “clearly bespeaks [the Congress's] intention that the EPA exercise discretion in determining which control measures must be implemented”). As stated in the proposal, EPA's longstanding interpretation is that RACT is defined as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” [15] Commenters correctly note that EPA has further explained that “RACT for a particular source is determined on a case-by-case basis, considering the technological and economic circumstances of the individual source.” [16]

EPA's action is in line with this longstanding guidance and other Agency actions concerning RACT under section 182 of the Clean Air Act. For each source, the EPA first selected a control technology that is reasonably available, considering technical and economic feasibility, and then identified the lowest emissions limitation that, in EPA's judgment, the particular source is capable of meeting by application of the technology (*i.e.,* that a plant operator applying the selected technology is capable of achieving economically and technologically). With respect to the first step, for this set of sources EPA selected SCR as the control technology that is reasonably available. For each of the sources addressed in this final rule, SCR has already been installed and each SCR has a clearly demonstrated operating history. Most of the sources installed these SCRs in the early 2000s, with the exception being Conemaugh, which only installed SCR in 2014. These facts alone prove that SCR is a control technology that is reasonably available for these sources. In the prior EPA-approved PADEP SIP revision, SCR was selected as the control technology and that selection was not disputed in comments on the action or in the subsequent litigation, to which this FIP is a response. Additionally, no one raised concerns about whether SCR was the appropriate control technology when EPA initially proposed approval of PADEP's RACT regulations, nor did anyone raise such concerns at the State level when PADEP undertook notice and comment rulemaking in order to adopt the regulation in the first place. To the extent that the commenters are challenging EPA's judgment in choosing the emission limit that each source is “capable of meeting,” those comments are addressed later in this section. However, if the commenters are asserting that EPA has selected a technology that is not “reasonably available considering technological and economic feasibility,” the EPA disagrees based on the fact that SCRs are present and operating at each of these sources.

Regarding the comment that EPA should select RACT limits for each mode of operation of the SCR, including startup and shutdown, the proposed FIP accounts for this. Given that these sources already have installed and operational SCRs, EPA determined it was appropriate to consider modes of operation, as applicable, during the selection of the emission limitation, rather than during the control technology selection. Indeed, EPA's proposed statistical approach to develop the rates is intended to select emissions limits that reasonably account for different modes, including consideration of modes where the selected RACT cannot be operated. As discussed in a comment response later in this document, EPA considered whether it was appropriate to create a tiered limit approach that also accounted for different modes in the different tiers, but as explained here and in the proposal, were EPA to define a mode where the chosen RACT technology need not operate but also fail to provide constraints on the use of that mode, that would essentially create an exemption from operating RACT when the source is clearly capable of meeting a lower rate, and would thereby create a regulatory incentive to operate at loads where the SCR is not in operation.

Comment: PADEP claims that it is inconsistent with RACT to use a statistical approach for the selection of emissions limits. Key-Con similarly claims that routine data are insufficient for a RACT analysis.

Response: As an initial matter, EPA affirms that a statistical approach is a valid way to select the lowest emissions limit that the source is capable of meeting through application of SCR. As explained in the response to the prior comment, once a technology is selected that is "reasonably available considering technological and economic feasibility," the second step is selection of the emission limit that a plant operator applying the selected technology is economically and technologically capable of achieving. In order to select the emission limitation, EPA did an extensive statistical analysis of emissions data from the affected facilities. The rationale underlying that approach is outlined in significant detail in our proposal.

EPA does not always have the benefit of a robust historic data set that reflects actual operation of the selected control technology to consider in selecting emission limits for purposes of establishing RACT. When, as is the case here, we do have such data, it is reasonable to use them. The proposal acknowledged several factors that affect the degree to which the historic data set represents the lowest rate that the source is capable of meeting and explains the adjustments EPA made to its proposed emissions limits to account for those factors. There are specific comments that take issue with certain choices EPA made in applying the statistical approach, which EPA addresses later in this notice, but nothing in the CAA or EPA rules or guidance precludes EPA from using a statistical approach as it has done here.

Comment: PADEP takes issue with EPA's decision to not do a technical and economic feasibility analysis for other potential NO_X control technologies at these sources, such as installation of newer low-NO_X burners that achieve greater NO_X reductions during the combustion process. Key-Con provided similar comments, asserting that our failure to analyze each of these other potential NO_X control technologies for their economic and technological feasibility was not in keeping with RACT. These commenters took issue with EPA's presumption "that the facilities have the flexibility to change their operations to emit less NO_X per unit of heat input."

Response: The statements discussing other potential NO_X control technologies that could be adopted, but that EPA was not requiring, were provided as additional information, and as noted in the proposal, "EPA did not evaluate these technologies in the context of our RACT analysis." Commenters appear to assume that EPA expressly accounted for installation or increased use of these technologies when determining limits that each source is capable of meeting. To the contrary, this discussion was intended to clarify that these other control techniques were not accounted for in EPA's development of each source's limits; neither the rates nor the weights were adjusted to require more use of these other control technologies. To the degree that a source was using such other control technologies during the period used in selecting the RACT limits, EPA's approach for developing the limits assumed that the sources continued to operate these other technologies without any change.

Also, although PADEP did an analysis of other NO_X control technologies available to each source when setting the limits in the permits, PADEP rejected all of these other control technologies except boiler tuning, either 🗋 for technical feasibility or cost reasons, in setting the limits. This rejection of most of the other control technologies as RACT by PADEP essentially aligns with our own selection of SCR as RACT. 🗋 Start Printed Page 53388

Comment: Homer City objects to applying the RACT limit from the lowest emitting of the three sources at the facility as a facility-wide RACT NO_X limit. Homer City asserts that the definition of RACT, *i.e.* ". . .the lowest emission limit that a *particular source* [emphasis added] is capable of meeting. . ." requires that EPA establish FIP limits on a unit by unit basis, rather than by a facility wide average.

Response: Longstanding EPA policies have allowed for averaging to meet RACT limits, including averaging across multiple emissions units. The 1992 NO_X supplement to the general preamble [17] states that it is appropriate for RACT to allow emissions averaging across facilities within a nonattainment area (or Ozone Transport Region (OTR) state, as is the case here). In practice EPA has allowed averaging across units on a facility-wide basis, and even across facilities in the same system under common control of the same owner/operator, including its approval of PADEP's prior EGU RACT rules.[18] EPA's implementation rule for the 2008 ozone NAAQS allows nonattainment areas to satisfy the NO_X RACT requirement by using averaged area-wide emissions reductions.[19] EPA reasonably allows averaging for compliance, so long as the underlying rates used as the basis for the average meet the definition of RACT. The comments do not provide a basis for EPA to reject its longstanding emissions averaging policies. To the contrary, these policies provide additional flexibility for sources to manage their SCR operation across units to ensure compliance with the limits.

Regarding the comments on EPA's proposal to base the facility-wide average rate on the best performing unit, the EPA is finalizing a minor change. In light of the unit-specific nature of EPA's weighted rate analysis, the EPA expects that the unit-specific rates already represent RACT for each unit, and that the most appropriate basis for a facility-wide average would be the weighted rates for each of the units at the facility. While some commenters felt that EPA should use the lowest single unit rate to drive facilities to use their best performing units most often, we expect that the stringent unit-specific rates, when averaged together, will still provide sufficient incentive to use the best performing units most often. See section IV of the notice for additional information.

Comment: Key-Con notes that only one of the designated nonattainment areas in Pennsylvania is currently violating the 2015 ozone NAAQS, and expresses concern that EPA appears to have inappropriately considered the potential for lower ozone levels in many areas in setting RACT, and states that the requirement for NO_X RACT is simply tied to Pennsylvania's inclusion in the OTR. Key-Con also asserts that it is more appropriate to use interstate transport rules, not RACT, to address concerns about states' obligations to eliminate significant contribution to nonattainment, or interference with maintenance of NAAQS in other states.

Response: The EPA agrees with the commenter's characterization that Pennsylvania must implement RACT level controls statewide due to the state's inclusion in the OTR, in accordance with CAA § 184. The statutory direction to require "implementation of reasonably available control technology" in states included in an ozone transport region, CAA §§ 182(f), 184(b), is the same in substance as the requirement for ozone nonattainment areas for "implementation of reasonably available control technology," CAA § 182(b)(2). Therefore, EPA's analytical method to determine what level of control technology is reasonably available does not differ based on whether RACT is being implemented in an ozone nonattainment area or the OTR.

There are also areas of Pennsylvania that are still designated nonattainment for both prior and current ozone NAAQS. EPA notes that the implication of the commenter's statement, that an area's factual attainment of an ozone NAAQS, as perhaps shown by a Clean Data Determination, would have implications for whether that area needs to implement RACT, is incorrect. An area designated nonattainment must continue to meet the statutory requirement to implement RACT, if otherwise applicable, until the area is redesignated to attainment or unclassifiable under section 107(d)(3) of the CAA. While the EPA did identify improved air quality in many areas, including remaining ozone nonattainment areas, some of which are in other states, as a benefit of the FIP emissions limits, we did not determine RACT through the selection of control technology and identification of emission limitations that the sources are capable of meeting based on the air quality impact in any particular area(s). In other words, air quality improvement in nonattainment areas in Pennsylvania or other states was not a criterion in determining RACT in this action.

Comment: Several commenters claim that EPA's economic feasibility analysis for SCR optimization was flawed. First, commenters assert that the economic analysis was flawed because it only considered the costs of additional reagent, and ignored considerable capital costs such as increased catalyst maintenance and replacement, and modifications to ancillary equipment. Second, commenters assert that the actual $/ton NO_X costs far exceed what EPA's analysis claims, and are more likely in the $150,000-200,000/ton range. Additionally, commenters assert that EPA's analysis of reagent injection incorrectly assumes that reagent costs will return to historic, lower prices.

Response: EPA disagrees. First, commenters are incorrect in the assertion that EPA did not consider capital costs, such as catalyst maintenance and replacement. As discussed in the NPRM and TSD, EPA relied on certain data from the recent evaluation of variable operating and maintenance (VOM) costs (which include increased catalyst maintenance and replacement costs), associated with increased use of SCRs at EGUs used in a number of national rulemaking actions related to the CAA's interstate transport requirements, including most recently the proposed Good Neighbor Plan for the 2015 ozone NAAQS. In the “EGU NO_X Mitigation Strategies Proposed Rule TSD” (Good Neighbor Plan TSD) for the proposed Good Neighbor Plan (included in the docket for this action), EPA used the capital expenses and operation and maintenance costs for installing and fully operating emission controls based on the cost equations used within the Integrated Planning Model (IPM) that were researched by Sargent & Lundy, a nationally recognized architect/engineering firm with EGU sector expertise. See 87 FR 31808 (/citation/87-FR-31808); TSD at 16-18. EPA's cost analysis for the proposed FIP only related to increased use, or optimization, of the SCRs, since each facility already had SCR installed. While that analysis was presented on a national, fleetwide basis, for this action EPA used site specific data in the “Retrofit Cost Analyzer” [20] to perform a bounding analysis to demonstrate that the cost assumptions made in the RCU and Good Neighbor Plan were still accurate and reasonable for the current RACT analysis. Using that methodology, EPA estimated a cost per ton for these sources that ranged from $2,590 to $2,757, depending on the unit. As previously stated, these estimates did include capital costs associated with increased catalyst maintenance and replacement. Reagent costs have actually dropped since the May 25, 2022 NPRM,[21] and the cost per ton of NO_X removed is still well within a range that should be considered economically feasible.

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In Table 4 of the TSD for the proposed FIP, EPA calculated the potential change in NO_X mass emissions, based on the proposed 30-day average NO_X emission limits.[22] Then, in Table 5 of the proposed TSD, EPA calculated the cost per ton of NO_X removed based on the additional amount of reagent needed to meet to those limits.[23] EPA has made slight adjustments in finalizing the emission limits after considering comments. Detailed discussion of the rationale for and of the limits themselves can be found elsewhere, but particularly in section IV of this preamble. Table 3 of this preamble shows the reductions these limits will realize when compared to 2021 emissions data.

Table 3—2021 Annual NO_X Emissions and Rates Compared to FIP Rates

Facility	2021 Average NO_X rate (lb/MMBtu)	30-Day NO_X rate (lb/MMBtu)	30-Day NO_X rate vs. 2021 average (%)	2021 NO_X emissions (tons)	Potential change in NO_X Mass Emissions (tons)	
Conemaugh	0.149	0.072	−52	5,506	−2,837	
Homer City	0.133	0.096	−28	3,144	−871	
Keystone	0.142	0.075	−47	5,481	−2,579	
Montour	0.110	0.102	−7	649	−46	
Net				14,781	−6,333	−43%

Based on the revised limits, and an updated cost of reagent, EPA calculated the cost per ton of NO_X removed for the final limits:

Table 4—Cost per NO_X ($/ton) Removed Based on Additional Reagent

Facility	Predicted reduction (tons NO_X per year from 2021 baseline)	Additional reagent (tons per year from 2021 baseline) *	Total annual cost for additional reagent ^	Cost per ton of NO_X removed for additional reagent ($/ton) +
Conemaugh	2,837	1,617	$2,263,800	$798
Homer City	871	496	694,400	797
Keystone	2,579	1,470	2,058,000	798
Montour	46	26	36,400	791
Average cost/ton				796

** Additional reagent = predicted reduction (tons) × 0.57 tons reagent/ton NO_X reduction.*

^ Total cost = additional reagent × $1400/ton reagent.

+ Cost per ton = total cost/predicted reduction.

Facility	Predicted reduction (tons NO_X per year from 2021 baseline)	Additional reagent (tons per year from 2021 baseline) *	Total annual cost for additional reagent ^	Cost per ton of NO_X removed for additional reagent ($/ton) +

With respect to the assertion by commenters that the $/ton value is actually in the $150,000-$200,000/ton of NO_X removed range, commenters have not supplied adequate data or analysis to substantiate that assertion. Commenters (in this case, Montour) merely assert that in order to meet the proposed limits, the units will need to run for extended periods of time following a startup, even when electricity is not being sold to the grid, in order to achieve a certain number of hours of low hourly NO_X emissions rates to offset the higher hourly NO_X emission rates during startup, or else the source will not meet the proposed emission limits in the FIP. Montour claims that it has more frequent start-ups and shut-downs during which it cannot operate the SCRs. EPA notes that the comment did not provide any analysis of potential alternate methods of compliant operation, and merely submitted data relating to the extra cost of fuel oil during the period of time they assert they will be required to run. For example, it may be possible for the units to ramp up more quickly following startup so as to spend less time in SCR-off mode. Additionally, it may be possible for the units to spend more time "hovering" at a higher heat input (*i.e.* SCR-on) in anticipation of a need for quick dispatch. EPA acknowledges that the limits in the FIP may result in the sources' needing to re-evaluate how they operate their EGUs in order to meet the new RACT limit, which may require adjusting the prices and certain operating parameters they specify to PJM when bidding into the market. However, EPA views these as free-market considerations, rather than an appropriate component of a RACT determination. EPA has long held that "[e]conomic feasibility rests very little on the ability of a particular source to `afford' to reduce emissions to the level of similar sources. Less efficient sources would be rewarded by having to bear lower emission reduction costs if affordability were given high consideration. Rather, economic feasibility . . . is largely determined by evidence that other sources in a source category have in fact applied the control technology in question." [24]

EPA continues to believe that optimization of the SCRs to achieve the NO_X emission limits in this FIP is economically feasible. Nothing submitted in the comments provided adequate justification or data to make a determination to the contrary. Indeed, evidence from the units' operating history supports EPA's view that when it is economically advantageous to do so, these units have no trouble meeting lower limits. Some of the lowest NO_X emissions EPA observed coincided with high NO_X allowance prices associated with the NO_X SIP call which went into effect in 2003.[25] Additionally, data for some of these units from May through June of the 2022 ozone season generally indicate SCR operating patterns (and, as a result, NO_X emissions) that match or are among their best in the recent data record. EPA believes this is due, at least in part, to the market prices of NO_X allowances needed for compliance with the RCU during this period, which were reported to range between $20,000 and $40,000 per ton.[26]

Comment: Commenters assert that EPA ignored equipment failure issues and failed to consider the deleterious effects on both control equipment and on the environment (ammonia slip, decreased mercury removal) of excess ammonia injection, particularly when operating below the catalysts' minimum effective temperature range. Commenters further assert that EPA failed to consider an engineering analysis submitted by Key-Con that PADEP relied upon in developing their case-by-case limit for Key-Con.

Response: EPA disagrees. First, EPA did not presume that the proposed FIP limits would be met by simply injecting more reagent during sub-optimal SCR operating conditions, and the FIP does not require it. EPA continues to recognize that the NO_X reduction capabilities of the SCRs are flue gas temperature dependent, and that the NO_X removal efficiency curve decreases with flue gas temperature until a point is reached where the SCR offers little or no NO_X control above what is achieved by the low NO_X burners (LNB) and overfire air (OFA) that are also installed on all of the units subject to this FIP. We also recognize that catalyst fouling, catalyst poisoning, ammonia slip and damage to downstream equipment are all potential outcomes of excessive reagent injection or injection during low temperature conditions. We further recognize that there have been changes in the electricity market in more recent years that result in greater periods of time when the units are operating in SCR-off mode. EPA believes that because the calculation of the limits uses actual past performance data from the sources, which include times at low heat input and therefore time with the SCR off, sources can meet these limits without injecting excessive amounts of ammonia during unfavorable SCR operating conditions. Additionally, using the third-best weight means that the SCR-off weight is based on a recent year that is not the extreme SCR-on case in the last decade and thus provides additional buffer.

The data show that during times when boilers are operating at high heat inputs and therefore SCRs are at optimum performance temperatures, sources have shown that they are capable of achieving limits in the 0.05 to 0.07 lb/MMBtu range, so they could achieve additional reductions during times when the SCR can be optimized to offset higher emissions during times when the SCR may not be optimized, so as to meet their 30-day rolling average and daily mass limit.

Also, EPA did review and consider the Key-Con engineering report referenced by the commenters. The information presented in that report appears to have been submitted to Pennsylvania to contest condition E.009 in PADEP's draft case-by-case RACT permit for Keystone, which would have required Keystone to set the SCR controllers at a target NO_X emission rate of 0.06 lb/MMBtu.[27] According to Attachment 3 of Key-Con's comment letter, they additionally evaluated operational data from 2019, which they claim is the last year of typical operations.[28] The report evaluated ammonia injection rates, and purported to show that due to ammonia slip and fouling of downstream appurtenances, the SCR could not and should not operate at a set-point of 0.06 lb NO_X /MMBtu. The report then determined that “a NO_X rate of 0.09 lb/MMBtu is tolerable and will not require air heater washes nearly as frequently as 0.08 lb/MMBtu [29] or less would.” See page 10 of Appendix 3 to Key-Con's July 11, 2022 comment letter. The report also states that Key-Con conducted testing on Conemaugh unit 1 during 18 days in May 2017 to determine if continuous operation at a NO_X setpoint of 0.04 lb/MMBtu was sustainable. The report claimed that it was not, because emissions of mercury spiked to a point where it appeared that Unit 1 would exceed its Mercury Air Toxics Standard (MATS) limit, and the NO_X setpoint had to be increased to 0.07 lb/MMBtu to lower mercury emissions. A similar test was conducted on Conemaugh Unit 2 towards the end of the 2017 ozone season to determine if the 0.05 lb/MMBtu setpoint was sustainable, and the report claims that after 25 days at the 0.05 setpoint, mercury emissions increased abruptly and nearly exceeded the MATS limit, so the NO_X setpoint had to be “relaxed” an unspecified amount to decrease mercury emissions. P. 7 of Attachment 3.

In response to the report, EPA notes that unlike Pennsylvania's proposed RACT permit terms, EPA is not requiring that the sources operate their SCRs at a certain set point below the 30-day rolling daily average NO_X rate limit, so the validity and relevance of this testing to EPA's proposed limits is questionable. EPA is expecting that the operators of Keystone and Conemaugh will operate their SCRs in a way that balances concerns about catalyst and preheater fouling and mercury emissions with the emission rates set by EPA—rates which are based on operating data from these sources indicating achievement of these emission rates in the past, including the recent past. Also, we note that EPA's pounds of NO_X per MMBtu of heat input emission rate limit is a 30-day rolling daily average emission rate limit, whereas its daily limit is a mass limit. In contrast, Pennsylvania's RACT permit had a daily (24 hour) average NO_X emissions rate, so EPA's 30-day rolling average emission rate limit gives the source operators more flexibility in how they operate the SCRs. That is, the operators do not need to keep the setpoint for the SCRs at a very low level each day for an extended period of time, as they would to meet Pennsylvania's daily average NO_X rate. The ability to average NO_X hourly emission rates over 30 days allows the sources greater flexibility to vary NO_X emission rates from their SCRs, raising NO_X emission rates up or down in order to balance the various factors that must be taken into account, such as catalyst or preheater fouling and mercury emissions.

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Finally, EPA notes that the commenter did not perform a "thorough review of EPA's NO_X emissions analyses" because of EPA's alleged technical failures and failure to understand current and expected unit utilizations.[30] However, the commenter did not provide any information regarding expected unit utilization, and instead criticized EPA's proposed rates as unobtainable during startup events by providing 25 hours of minimal data regarding one cold-start of Keystone Unit 1 in January 2022. Given that this data covered only 25 hours of startup, and was not then averaged with 29 other days of emission data to arrive at a 30-day average hourly emission rate, it is not proof that this one unit could not meet EPA's 30-day average rate. Absent more robust data to support commenter's claim, EPA declines to amend its proposed rates for the four units at Keystone and Conemaugh based on the thin data presented.

Comment: PADEP asserts that EPA's weighted rate approach is flawed because it relies on an analysis of past averages, which is contrary to the court's instruction that ". . . an average of the current emissions being generated by existing systems will not usually be sufficient to satisfy the RACT standard."

Response: EPA disagrees with the commenter's contention that the analysis underlying EPA's RACT limits is flawed simply due to the fact that EPA uses the mathematical function of averaging as part of the Agency's overall calculation. As the commenter notes, the *Sierra Club* decision does include language noting that "an average of the current emissions being generated by existing systems, will not usually be sufficient to satisfy the RACT standard." 972 F.3d at 300. However, in the preceding sentence, the court provides necessary context for its statement and a helpful summary of what Pennsylvania provided in its prior SIP, EPA's approval of which the Court was vacating. The Court notes that the chosen emission limitation "was selected as it represents the average pollution output of the three plants that are already compliant over the past five years." *Id.* Therefore, the court did not take issue with the mathematical function of averaging; it took issue with the quantity being averaged, and its application in setting RACT. EPA does not believe that the court meant to forbid the use of any averaging in the determination of RACT, so long as it fit within the definition of RACT and the use of such averaging was adequately and reasonably explained in the record.

As explained elsewhere in this action, EPA has used a statistical approach to establish the emission limitations contained in this FIP, which necessarily involves averaging. However, there are significant and meaningful differences between EPA's use of averaging and how PADEP previously used averaging to determine the RACT limits at issue in the *Sierra Club* decision. While Pennsylvania's limit was based on a five-year ozone season average from three plants that were then averaged together again to calculate a single limit required at five different sources, EPA's approach uses a source-specific third-best ozone season rate from a larger range of data. EPA's approach is consistent with the RACT definition, including the interpretation of RACT contained in the *Sierra Club* decision, because it is aimed at representing the lowest rate the source is technologically and economically capable of achieving, not the average rate it has already achieved. (As explained elsewhere in this action, EPA used third-best to represent the source's current capability, but the approach is still aimed at defining the lowest rate, rather than a 5-year overall average).

Comment: PADEP asserts that EPA's FIP is flawed because it relies on the third-best approach used in the RCU and Good Neighbor Plan, which is inappropriate because those rules evaluated more current data sets, and that EPA's data set selection is not driven by RACT regulations or guidance and does not set source specific limits considering technological and economic feasibility.

Response: EPA proposed to use the third-best ozone season rate for each source based on the idea, which was also cited in both the RCU and the Good Neighbor Plan, that the performance of SCRs degrades over time, and that usually only one layer of catalyst is changed/refurbished per year. Therefore, the SCRs may never be able to achieve the same emission reduction rate as when they started operating and all three catalyst layers were new. With the exception of the Conemaugh plant, which installed its SCRs in late 2014, the other sources installed their SCR by 2003.[31] Thus, many other parts of the overall SCR system, such as the reagent injection system, may also have deteriorated in performance. The use of the third-best year for each source is consistent with EPA's past practices in other rulemakings, and also has a basis in the performance data of each source. The third-best approach is a reasonable way of determining appropriate RACT limits. It avoids biasing the SCR-on limit with uncharacteristically low emitting ozone seasons, or under uncharacteristically optimal operating conditions. As stated in the April 6, 2022 proposed Good Neighbor Plan, the EPA found it prudent not to consider lowest or second lowest ozone season NO_X emissions rates, which may reflect SCR systems that have all new components. Such data are potentially not representative of ongoing achievable NO_X emission rates considering broken-in components and routine maintenance schedules. Additionally, the fact that CSAPR and the Good Neighbor Plan establish caps rather than limits does not preclude the use of the third-best approach for the purposes of the FIP. EPA is finalizing the use of the third-best year for all of the facilities except Conemaugh. As discussed elsewhere in this action, EPA has determined it is appropriate to use a different approach for establishing final RACT limits for Conemaugh due to the fact that Conemaugh has newer SCRs. As further discussed in section IV of this preamble, Conemaugh's final limit was calculated using the second-best rate and the second-best weight due to the more limited data set of years available for this facility based on the more recent installation of SCR. [32]

Regarding the claim that the RCU and Good Neighbor Plan used more current data sets, this is because those rulemakings were undertaken under a completely different statutory provision with different requirements and purpose than this FIP. Both the RCU and Good Neighbor Plan FIPs were addressing the requirement in section 110(a)(2)(D)(i)(I) of the CAA to ensure that emissions from upwind sources, including EGUs, were not significantly contributing to nonattainment or interfering with maintenance in downwind areas. The RCU addressed upwind significant contributions to downwind areas for the 2008 ozone NAAQS, while the proposed Good Neighbor Plan addressed upwind emissions for the 2015 ozone NAAQS. As such, for both rules, EPA needed to use the most recently available and up-to-date data for both source emissions and ambient air monitoring results in order to identify upwind emissions currently affecting downwind monitors for the 2008 and 2015 ozone NAAQS. Here, the purpose is to identify RACT, as required under subsections 182(b)(2), 182 (f)(1), and 184 of the CAA, which requires that major sources of NO_X and/or VOCs in nonattainment areas, or in the OTR, meet RACT, which EPA defines as “the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” Given this different purpose, the examination of historic operating data for the SCRs is relevant to the determination of the NO_X emission rates each source attained while running their SCRs, and which the source was therefore capable of meeting. Also, EPA did consider ozone season emission rates from each source through 2021, which was the most recent data available at the time of the proposal, so PADEP's claim that EPA did not consider recent data is incorrect.

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Comment: PADEP further asserts that EPA's FIP is flawed because it only considers ozone season data, so fails to consider emissions for a major part of the year. Commenters claim the court acknowledged that their presumptive limit did account for seasonal variability. They cite to *Motor Vehicles Mfrs. Ass'n of the U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983) (“State Farm”)* (Providing that “the agency must examine the relevant data and articulate a satisfactory explanation for its action including a “rational connection between the facts found and the choice made,” and claim that because EPA failed to consider the majority of the operational emissions data (*i.e.,* non-ozone season), EPA failed to adequately demonstrate that the proposed limits are technically and economically feasible year-round.

Response: EPA disagrees with PADEP's claim that EPA should consider non-ozone season data for several reasons. Although these sources were subject to the CAIR annual NO_X requirements starting in 2009 and the CSAPR annual NO_X requirements starting in 2015, these cap and trade programs initially set annual NO_X emission budgets for states based on a NO_X emission rate of 0.15 lb/MMBtu starting in 2009, then based on a cost-effectiveness level starting in 2015, and allowed individual sources to exceed their allocated allowances by a certain percent by purchasing additional NO_X allowances from other sources. As such, the non-ozone season emissions data beginning in 2009 does not necessarily reflect the NO_X emission rates these SCRs are capable of achieving outside of the ozone season because the SCRs were not required to meet a specific NO_X emission rate. Second, post-2017 (when Pennsylvania's RACT II limit of 0.12lb/MMBtu was effective), data show the sources generally did not operate the SCRs for significant time periods outside of ozone season. Hourly operating data submitted by Keystone and Conemaugh to PADEP show that in 2017, the SCRs did not consistently operate outside of ozone season, with the units at each source often cycling down to low heat inputs at night and therefore not operating their SCRs.[33] Third, Pennsylvania also based the 0.12 lb/MMBtu emission rate in its RACT II rule solely on ozone season emissions data. Finally, PADEP does not explain why EPA's determination of RACT for these sources would be altered by consideration of non-ozone season data.

Comment: Several commenters objected to EPA's methodology (and thus, results) in calculating the SCR-on/SCR-off thresholds. PADEP in particular asserts that by assigning an operating threshold for SCR operation at each facility, EPA has run afoul of the Court's objection to the 600-degree threshold in Pennsylvania's original RACT II regulation. Further, PADEP asserts that because EPA had only limited information from Key-Con and none from the other facilities, and because we failed to seek such information from the other facilities, the resulting emission limits are unsupported. Another commenter asserted that EPA's visual evaluation of scatterplot data to develop the thresholds was flawed, and that rather than accurately depicting the SCR-on/SCR-off thresholds, the diagrams actually depict the minimum sustainable load for the unit, which is ". . . typically the level at which PJM places a unit at low load for spinning reserve during periods of low demand." See Homer City Comments at 2. Additionally, commenters assert that the use of 0.2 lb/MMBtu as an indicator of when the SCRs are or are not running is arbitrary, since there are times when an SCR is off, but the NO_X emissions are below 0.2 lb/MMBtu, and conversely, there are times when an SCR is running, but the NO_X emissions are greater than 0.2 lb/MMBtu.

Response: First, EPA disagrees with Pennsylvania's assertion that the methodology for determining the SCR-on and SCR-off weights and rates using observed SCR thresholds in the data for purposes of developing an emissions limit that would restrict SCR-off operation is substantially similar to PADEP's use of the 600-degree threshold to justify essentially unlimited SCR-off operation. EPA further disagrees that the *Sierra Club* adverse decision concerning the 600-degree threshold has direct relevance to the permissibility of the approach used by EPA in utilizing SCR-on and SCR-off weights and rates. The Court found that Pennsylvania's blanket 600-degree temperature threshold, which Pennsylvania applied uniformly to all the sources regardless of the differences in SCRs at each source, was inadequately explained or supported by the record. 972 F.3d at 303 ("Regarding the threshold, neither the EPA nor DEP can explain why it is necessary at all. . . . [E]ven assuming such a temperature threshold were reasonable, the record does not support the conclusion that 600 degrees Fahrenheit is the proper limit.") EPA's SCR-on and SCR-off thresholds were derived through careful unit-by-unit observation of actual operating data. Furthermore, rather than drawing a regulatory line below which less stringent emissions limits apply without any restriction on operating time, EPA used the 0.2 lb/MMBtu threshold to divide the operational data into SCR-on and SCR-off categories, then used those data to establish both average SCR-on and -off rates for each unit, and to identify the unit's past percentage of ozone season time with the SCR on or off to establish the weight applied to the respective rates. As such, the 0.2 lb/MMBtu is not an enforceable limit, but merely a data point that was one component of EPA's approach to use historical operating data to derive the lowest emission limit that these particular sources are capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. Start Printed Page 53393

As for the assertion that the 0.2 lb/MMBtu cutpoint is arbitrary, EPA conducted a fleetwide analysis of EGUs with combustion and post-combustion NO_X controls and found that this rate indicates that the SCR is running to some extent.[34] Nevertheless, in response to our May 25, 2022 (87 FR 31798 (/citation/87-FR-31798)) proposal, EPA did in fact receive additional information from certain sources (Montour and Homer City) regarding what they consider the proper megawatt (MW) threshold for operation of their SCRs. As described in section IV of this preamble, we have taken that information into account in developing the NO_X emission limits finalized in this action.

Comment: PADEP asserts that EPA's statistical approach to RACT in this case has led to absurd results, specifically a higher limit for Conemaugh than for Homer City and Keystone, despite the fact that Conemaugh's SCRs are newer and technically capable of achieving lower NO_X emission rates.

Response: EPA has developed the emissions limits for each source based on analysis of historical data for each source demonstrating what emissions the sources are capable of achieving through operation of their installed SCR equipment. The emission limits being established for Keystone are based on analysis of historical data extending back to 2003, while the emissions limits being established for Conemaugh are based on historical data extending only back to 2015 due to the more recent SCR installations at Conemaugh. Because the shorter historical period of the Conemaugh data set does not contain periods with high NO_X allowance prices that would necessarily have motivated Conemaugh to try to achieve the lowest possible emissions, it is possible that EPA's resulting emissions limits for Conemaugh are less stringent than would have been established with a more extensive data set. However, the limitations of the data available for Conemaugh in no way render the Keystone emission limits unreasonable. Nevertheless, the comment does illustrate that EPA should adjust its approach to account for the more limited Conemaugh data. As further discussed in section IV of this preamble, in response to comments received, EPA is finalizing limits that differ slightly from what was proposed, including an adjustment for Conemaugh that better accounts for the more limited set of ozone seasons from which to draw data for this source, while also addressing the circumstances that prompted the PADEP comment regarding absurd results. The Agency determined that for Conemaugh, it is reasonable to use the second-best weight instead of the third-best.

Comment: PADEP asserts that EPA should have considered tiered limits as they did, and that such a limit structure would, in fact, result in optimized SCR operation.

Response: EPA disagrees that we needed to establish a tiered limit structure like the one that was vacated by the Court, or the similar approach used by PADEP in their case-by-case permits. As explained in the proposal and the earlier section of this preamble, EPA did consider the appropriateness of tiered limits and opted to not propose such an approach for several reasons. First, while the Court did not explicitly preclude the threshold approach, they were clearly suspicious of its appropriateness: “Regarding the threshold, neither the EPA nor DEP can explain why it is necessary at all. It is not a common exemption.” *Sierra at 20.* Upon reconsideration, EPA believes that it is not necessary. EPA continues to believe that constraining SCR-off operation to the extent possible based on data reflecting the recent operations of each source is the appropriate means of implementing emission limits consistent with RACT. As EPA raised in the on-record comments we submitted to PADEP on draft permits,[35] it is not clear to EPA how a tiered limit approach constrains SCR-off operation in any meaningful or enforceable way.[36] Moreover, unconstrained SCR-off operation would be inconsistent with the Court's directive that the RACT limit must be technology-forcing.[37] A set of limits that does not place limits on the source operating without its NO_X control technology is not technology-forcing. Accordingly, EPA has chosen to forgo the tiered limit approach, and instead use a weighted rate approach, which we continue to believe provides the sources flexibility to address current operational realities (*i.e.,* increased cycling), while at the same time providing meaningful constraint on SCR-off operation and objective enforceability.

Comment: Talen Energy (Montour) asserts that EPA's limits are so restrictive that they extend the regulatory regime beyond the customary regulation of air pollutant emissions, and in effect dictate operation of units and may severely limit the ability of the units to run as directed by PJM and potentially compromise grid reliability.

Response: EPA disagrees that these FIP limits are too restrictive or that they extend the regulatory regime beyond EPA's Clean Air Act authority or customary EPA action in a way that is inappropriate or inconsistent with past CAA implementation. Emission limitations are, by definition, a limitation on the amount of pollutants that may be emitted by a source and therefore all emission limits place restrictions on how sources operate in some fashion. For example, states or EPA may place enforceable requirements on sources for throughput limitations; federally enforceable requirements of this nature are a standard practice that substitutes for major source applicability of new source review (NSR) or national emission standards for hazardous air pollutants (NESHAPs). Some emission limitations may also take the form of work practice standards, which could place requirements on the type of fuel a source may use or limit the amount of time a source may operate under a certain status. These FIP limits do not prescribe when or how the affected units should operate in order to generate electricity. Rather, these limits ensure that when the units are operating, their already installed SCRs are also operated in a way that achieves the lowest emission rates that are technically and economically feasible.

As discussed previously in this notice, EPA acknowledges that the weight given to the proposed SCR-off limit has the effect of limiting the portion of time a cycling source can operate in SCR-off mode and incentivizes a source to shift to SCR-on mode to preserve headroom under the limit. While driving SCR operation, the weighted limit accommodates the need for an EGU to occasionally cycle down to loads below which SCR can operate effectively. Nothing in the FIP being finalized in this document is intended to prohibit SCR-off operation, nor does it dictate specific times when SCR-off operation would not be permitted to occur.

Comment: Montour commented that the compliance date should be extended and not be the same date as the effective date of the regulation. Citing the need to identify and evaluate the updates/changes necessary, update programming for the CEMS and process control equipment, provide training to staff, and complete operational trials, Montour suggested extending the compliance date by six months. Other sources commented that EPA should not proceed at all with a final rule at this time and instead seek an extension from the Court to reconsider the proposed limits.

Response: Before addressing the substance of this comment, EPA would like to correct an error in the NPRM regarding the effective date of the FIP. The effective date of the regulation was intended to be conveyed as an editorial note that the rule would be effective 30 days after publication of the final rule. Instead, the editorial note was converted into an actual date by the publisher, which was 30 days after the date the proposed rulemaking was published: June 24, 2022. This was a typographical error that produced an absurd result:

the rule could not possibly be effective before a final approval, or indeed, even before the public comment period had ended (on July 11, 2022). The proposed compliance date was accurately described to “commence immediately upon the effective date.” [38]

With regard to Montour's request to extend the compliance date, EPA agrees there will be a certain amount of time required for the facilities to adjust to the new requirements and make certain technical and administrative changes to ensure operations comply with the new RACT limits. After considering comments received on this rulemaking, EPA has determined that it is appropriate to extend the compliance date past the initial proposal of 30 days after the effective date of these regulations. The commenters have raised compelling concerns about being able to meet new, more stringent limits on the accelerated timeline. In light of the comment received from Montour, EPA is finalizing a compliance date of 180 days after the effective date of the FIP. EPA is under Court Order to “. . . either approve a revised, compliant SIP within two years or formulate a new [FIP],” which EPA interprets as requiring a final rule by August 27, 2022. Therefore, EPA will finalize the final rule in compliance with the Court.

Comment: Homer City asserted that EPA's description of the methodology for determining SCR-on and SCR-off weighting is inadequate to allow for independent verification. Also, Homer City also commented that there is no explanation as to why the SCR-off weights (0.00 or 0.01) are so small, which leave no margin for SCR-off operation.

Response: The commenter did not provide adequate explanation as to why or where it had difficulty in understanding or replicating the calculations EPA outlined in the proposed notice. Homer City also did not submit its attempted calculations for EPA's consideration. All of the data EPA used to develop the proposed emission limits (including that which was used to establish the SCR-on and SCR-off weights) was either available in the docket, or, because of file type and size limitations of *www.regulations.gov (http://www.regulations.gov),* was available upon request.[39] Other commenters were able to replicate and/or modify EPA's methodology. Homer City's weights are representative of their ozone season operation over the time period analyzed for the weights (2011 to 2021). Further discussion of their revised weights can be found in section IV of this preamble.

Comment: Sierra Club asserts that the requirement that the sources submit reports of their compliance every six months should be shortened to every three months (quarterly), because the information needed to demonstrate compliance with the FIP is already submitted to EPA for various purposes on a quarterly basis, and that it does not make sense for the FIP to require less frequent (biannual) reporting. In addition, if EPA elects to keep the FIP reporting data separate from reporting to the Clean Air Markets Division, Sierra Club requests that EPA put a mechanism into the FIP by which the public can readily access this data to ensure compliance, such as posting that data to the Clean Air Markets Program Data tool. Finally, the commenter requests that the FIP recordkeeping requirements be updated to include information about SCR runtime and/or bypass as well as reagent usage.

Response: EPA selected the six-month reporting period in order to be consistent and streamlined with the sources' existing title V reporting requirements. These title V reports are submitted to EPA Region 3 and the state for review. The fact that certain data used to determine compliance with the FIP requirements are also reported quarterly to other EPA offices under various programs, such as the Acid Rain program and Cross State Air Pollution Rule, and then placed into EPA's Clean Air Markets Data Program online tool, does not provide a sufficient basis to increase the frequency of reporting compliance with the FIP requirements to match the reporting frequency for the underlying data. There is nothing about the FIP limits that would necessitate a reporting frequency greater than the reporting frequency required by title V. The FIP does require deviation reports to be submitted to EPA when NO_X emission limits have been exceeded for three or more days in any 30-day period.

With respect to the assertion that the reporting requirements should be updated to include SCR runtime and reagent injection data, EPA believes that reporting of CEMS data consistent with title V requirements is sufficient for compliance demonstration purposes. EPA has not tied the emission limits directly to SCR operating parameters in a way that would necessitate the submission of additional SCR data. Compliance with the emission limits is the ultimate regulatory requirement, and this is adequately demonstrated through submission of CEMS data. EPA does not believe it is appropriate at this time to include reporting requirements to this FIP that are not directly necessary to show compliance with the regulatory requirements finalized herein.

Regarding the assertion that EPA should provide mechanism by which the public can readily access additional data beyond the regularly reported emissions data to ensure compliance, such as posting that additional data to the Clean Air Markets Program Data tool, EPA is not taking that step at this time. There is nothing about the NO_X limits in this FIP which would require EPA to provide a novel approach to providing access to additional compliance data. Further, the tools EPA makes available for providing the public with access to reported emissions data are not at issue in this proceeding, and comments requesting changes to those tools are outside the scope of the rule.

Comment: Sierra Club asserts that EPA should have used the best year, rather than the third-best, which is what EPA used in establishing the SCR-on rate. First, they assert that EPA has not established that control equipment degrades over time, and that by selecting the third-best ozone season, EPA is allowing sources to forgo maintenance and good operating practices that would allow them to otherwise meet limits that were established on a best ozone season basis. Further, pointing to the rates achieved during the period of 2003-2010 when NO_X allowance prices were high due to the NO_X SIP call, Sierra Club asserts that the decline in SCR performance is due not to equipment degradation, but to the lack of a regulatory requirement to achieve better emissions. Finally, Sierra Club asserts that an examination of the best performing years does not support the idea that equipment degradation due to the passage of time necessarily leads to an inability to meet lower limits, and again asserts that higher emissions rates are tied to less stringent regulatory requirements rather than equipment degradation.

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Response: EPA disagrees that we should have used the best ozone season instead of the third-best to establish the SCR-on rate. First, although equipment degradation is not the only consideration we evaluated when selecting the third-best approach, it is certainly a contributing factor. While degradation can be slowed or mitigated through proper operation, there is little question that it occurs and can impact the removal efficiency. EPA has explained this previously that "[o]ver time, . . . the catalyst activity decreases, requiring replacement, washing/cleaning, rejuvenation, or regeneration of the catalyst." [40] EPA acknowledges that catalyst management practices can be adapted to address catalyst degradation, but that does not mean that the degradation does not occur.

In addition, EPA's longstanding interpretation of RACT does not require RACT-level controls to be equivalent to the "best." The Court agreed with this interpretation in the *Sierra Club* decision: "we do not suggest that Pennsylvania must achieve the absolute lowest level of emissions that is technologically possible for the approved limit to satisfy RACT." [41] As explained in the NPRM and in response to the previous comment, EPA believes that the third-best approach is a reasonable way of establishing appropriate RACT limits. Use of the third-best year avoids biasing the limit with uncharacteristically low emitting ozone seasons, or under uncharacteristically optimal operating conditions.

EPA does agree with the commenter that there does appear to be a correlation between increased SCR operation (and correspondingly lower NO_X emissions), and periods when new regulatory requirements such as CAIR, CSAPR, the CSAPR Update, and the RCU, have created meaningfully more stringent NO_X emission budgets. More stringent emissions budgets can compel EGUs to operate their SCRs more often and at lower NO_X emission rates to meet these new budgets. They accomplish this result by raising the cost of NO_X allowances, creating an economic incentive for EGUs to operate their SCRs more often and at lower NO_X emission rates to either avoid having to purchase costly allowances or to generate NO_X allowances to sell. EPA continues to believe that our proposed weighted rate approach takes these factors into consideration and establishes appropriate limits that are consistent with the CAA's RACT requirements.

Comment: Similar to comments relating to EPA's consideration of operating data from years when the units were operating in a base load capacity, commenters assert that ozone season operations are not consistent with year-round operations and therefore should not be the sole timeframe considered in development of the limits that apply all the time. Further, Key-Con in particular noted that the SCRs at Keystone were designed to only run during ozone season, and that in the past, they had considerable down time for cleaning and maintenance of the controls. Additionally, they assert that ammonium bisulfate salts (ABS) form more readily in colder ambient temperatures, leading to increased fouling.

Response: EPA acknowledges some of the technical challenges associated with temperature and SCR activity. Because of this, among other reasons, we performed an analysis of actual operating and emissions data and developed reasonable limits to account for challenges such as seasonal ambient temperature changes and increased cycling operation rather than selecting the absolute lowest rates that these units have ever achieved. EPA primarily used ozone season data to develop these limits, which is appropriate, not only because the ozone season generally represents a period of increased electricity demand and operation at these sources, but also because it is indicative of what these units can achieve when there are additional regulatory constraints and economic disincentives against sub-optimal SCR operation in place.

To the degree that the comment is suggesting that this RACT FIP should create seasonal limits that do not require SCR operations in non-ozone-season months, the EPA does not believe that this would be consistent with the CAA RACT requirement. As noted in the background of this preamble, NO_X RACT for major sources is required to be applied year-round. There are numerous coal-fired EGUs operating in the OTR that operate SCR controls on an annual basis. Additionally, there are coal-fired EGUs operating outside the OTR subject to other regulations that mandate SCR controls be operated throughout the year as well. Like the four Pennsylvania facilities addressed in this notice, many of these other coal-fired EGUs were built in the same era (1960s and 1970s) and then later retrofitted with SCRs in response to the EPA interstate transport requirements for ozone season NO_X emissions, which began in 2003. So, while EPA has applied RACT on a case-by-case, source-specific basis, EPA cannot ignore the fact that there are many coal-fired EGUs, outside of Pennsylvania, that can, and do, operate their SCR controls year-round with NO_X emission limits similar to the final limits determined in this notice for the purposes of NO_X RACT as well as for other regulatory requirements.[42]

EPA also disagrees that the Keystone units cannot operate their SCRs effectively outside of the ozone season or that the rates must be further adjusted to account for seasonal effects. In response to Keystone's comment, EPA further reviewed non-ozone season emissions data reports for Keystone units and found that between 2009 and 2010, both Keystone units operated their SCRs in non-ozone season months for extended periods whereby their NO_X emissions were generally below the final NO_X emission limits determined in this notice.[43] Therefore, EPA cannot justify exempting Keystone from operating its SCRs, with reasonable effectiveness, for NO_X RACT during non-ozone season months.

Comment: Key-Con asserts that EPA's limits severely and inappropriately limit the amount of time either facility can operate without ammonia injection, especially during start-up and low load operation. They further assert that the duration of a cold start-up is 18-24 hours, and that at loads between the minimum sustainable load (340 MW) and the unit load (which they do not identify) where the minimum continuous operating temperature (MCOT) of the SCR is reached, emissions can reach 0.35 lb/MMBtu for Keystone units, and 0.30 lb/MMBtu for Conemaugh. They assert that Keystone units 1 and 2 in particular would be unable to demonstrate compliance if there was one cold start-up in a 30-day period, even if they spent the rest of the time operating at the proposed limit of 0.074 lb/MMBtu.

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Response: Key-Con's comment is not sufficient to demonstrate an inability to meet the proposed FIP limits. Key-Con presented no data to justify the amount of time spent in a cold start-up during which the unit load is above the sustainable limit, but below whatever threshold is necessary to bring flue gas up to the MCOT of the SCR and begin ammonia injection. As noted in a previous response, Key-Con did not provide any information regarding expected unit utilization, and instead criticized EPA's proposed rates as unobtainable during startup events by providing 25 hours of minimal data regarding one cold-start of Keystone Unit 1 in January 2022. Given that this data covered only 25 hours of startup, and was not then averaged with 29 other days of emission data to arrive at a 30-day average hourly emission rate, it is not proof that this one unit could not meet EPA's 30-day average rate.

In response to this comment, EPA further reviewed startup data for Keystone in non-ozone season months. On November 5, 2009, Keystone Unit 1 started operations after having been inoperable since October 20, 2009. During the first three days of operation, the daily NO_X emission rates were 0.229, 0.160, and 0.058 lb/MMBtu respectively. During the subsequent days of operation, up until reaching 30 operating days, the daily NO_X emissions varied from a low of 0.046 to a high of 0.116 lb/MMBtu. The resultant 30-day NO_X emission rate after 30 days of operation was 0.064 lb/MMBtu.[44] This is well below the final NO_X emission rate limit determined in this notice of 0.075 lb/MMBtu. This example illustrates that the unit is entirely capable of achieving the emission rate limits in this notice, with startup periods, provided the normal operating days are sufficiently controlled and the facility was able to achieve these results without a specific 30-day regulatory requirement to do so. Moreover, EPA has purposely granted an emission rate averaged over 30 days, which is the maximum averaging time EPA can grant for NO_X RACT. EPA has also issued facility-wide emission rate limits to allow the facilities to further average the emission rates amongst their units. This amount of dual averaging, in terms of averaging days and then units, affords Key-Con, and the other facilities, additional flexibility to manage startup operations.

Further, even if we are to accept this claim on its face, Key-Con's argument fails because they merely point out the obvious mathematical certainty that any appreciable amount of time spent operating above the average limit would lead to a violation if the entirety of the remaining averaging period was spent operating exactly at the limit. The entire purpose of establishing average limits (and in this case a 30-day average) is to smooth out the peaks and valleys of shorter-term emissions and arrive at a limit that can be met by offsetting periods when the units emit above the limit (generally, SCR-off periods), with periods of optimal operation where the units emit below the limit (generally, SCR-on periods). This is one of the reasons that we did not select the lowest achievable SCR-on rate as RACT. EPA's limits provide for some level of SCR-off operation, while still representing the lowest rate the source is capable of meeting over such period through the application of control technology that is reasonably available considering technological and economic feasibility. To the degree that this limit acts as a constraint on low-load operation without the SCR, the commenter did not explain why such a constraint is inappropriate. In light of the high NO_X emissions that can occur with such operation, the EPA believes this is a reasonable approach to define a limit that represents the application of RACT. Moreover, Key-Con's own analysis appears to support an ability to meet 0.075 lb/MMBtu, even based on cold start-ups taking place in January.[45] As discussed in section IV of this preamble, EPA has re-evaluated our proposed limits, with the resulting limits being consistent with what Key-Con's comments appear to show is attainable.

Comment: Homer City asserts that because the proposed 24-hour mass limits are based on the 30-day average rate limits, the mass limits do not provide adequate margin for periods of start-up and shut down.

Response: EPA disagrees. First, as previously discussed, the 30-day rate-based limits upon which the daily mass limits are based were derived in such a way as to incorporate several layers of flexibility, or margin, including emissions during periods of startup and shutdown. We used weighted averages considering years when the units were operating in more of a load-following mode rather than as baseload, we used a 30-day averaging period to “smooth” variability of shorter-term emissions, and we used the “third-best” rather than the “best” approach in order to add additional buffer and still establish limits that represent RACT. Additionally, it is not clear what period of time the commenter is considering as “startup,” nor have they established that they could not begin operating the SCRs sooner. While emission rates during the startup process do tend to be higher before the control equipment is fully operational, mass emissions are typically lower for most startup hours, since startup generally happens at lower levels of fuel combustion. Finally, commenters have not presented any actual operating data to demonstrate that they cannot meet the proposed limits. Indeed, EPA's review of historical data, and in fact, some data from the 2022 ozone season reported so far, supports a determination that the sources can achieve EPA's final 30-day NO_X emission rate limits, and that when the units operate in compliance with the 30-day rate limit, they have generally operated below the final daily NO_X mass emission limits.

Comment: Homer City claims that EPA's proposed limits are not technically feasible because, they assert, from 2010-2021, only Keystone and Conemaugh Units 1 and 2 have been able to achieve EPA's proposed limits on a 30-day basis, and even then, it was only 7 instances or 6.36% of the time.

Response: First, if sources were not meeting the proposed limits in the selected years during which there was no regulatory requirement or economic incentive to do so, it is not necessarily proof that they could not have. Nor is it proof that they cannot in the future. EPA notes that in rejecting EPA's approval of PADEP's original 0.12 lb/MMBtu limit as “a mere acceptance of the status quo,” 972 F.3d at 302, the Court in *Sierra Club* affirmed that “an average of the current emissions being generated by existing systems, will not usually be sufficient to satisfy the RACT standard,” *id.* at 300. Homer City rejects EPA's limits, but presents no data or analysis that demonstrates what they are in fact capable of achieving, and what EPA should establish as RACT for these units. EPA has demonstrated that the limits are achievable when the regulatory environment requires it, and that the limits in the FIP represent RACT for these sources.

Comment: PADEP asserts that EPA's FIP is based on an incomplete record. First, PADEP asserts that EPA ignored information that the Department obtained from the sources and failed to obtain additional information that would be necessary to conduct a source specific RACT analysis. Additionally, PADEP claims that meetings between EPA staff and the Maryland Department of the Environment (MDE) prior to our proposal may be relevant to the development of the FIP, and that records from that meeting should have been in the docket.

Response: EPA disagrees. First, to the extent it was relevant to our approach, we did consider the information that PADEP obtained and submitted, and in fact cited to it on numerous occasions, and included it in the record as appropriate. EPA had a sufficient technical basis, that is thoroughly documented in the rulemaking record, to support the RACT limits included in this FIP. To the extent that PADEP or the sources at issue in this rulemaking believe the Agency should have considered additional or alternative data, the 45-day comment period provided an opportunity for the sources to submit such information. EPA considered all of the additional information submitted prior to finalizing the FIP. With respect to the assertion that records from EPA's discussions with MDE prior to EPA proposing this action should have been contained in the record, EPA disagrees. All documentation and information that EPA relied upon in developing this rule action have been included in the record. The cited discussion with MDE did not contain information that was relied upon for development of the FIP approach and limits.

Comment: Montour submitted a technical analysis which built upon EPA's methodology in the May 25, 2022 (87 FR 31798 (/citation/87-FR-31798)) NPRM in order to demonstrate what they felt are more achievable limits, based on a dataset that represents what Montour contends are more consistent with current operating parameters. Montour asserts that EPA should have only considered ozone season data from 2017-2021, that the correct SCR threshold is 440MW, and that as a result, Montour should have a facility-wide, 30-day NO_X emission rate limit of 0.099 lb/MMBtu, with daily mass-based limits of 17,385 and 17,200 lb NO_X /day for Units 1 and 2, respectively.

Response: As further discussed in section IV of this preamble, as a result of comments received and while largely retaining the methodology described in the NPRM, EPA has revised some of the limits from the proposal based on the submittal of additional data or the reconsideration of some of the weights in the case of Conemaugh. Specifically, in cases such as Montour where a facility submitted SCR threshold data to counter that which EPA used in the proposal, EPA recalculated the NO_X rate limits using the facility's information, but EPA's original methodology. In the case of Montour, this recalculation resulted in limits that are very much in line with the alternate limits proposed by the facility in its technical analysis. Specifically, EPA's methodology resulted in a facility-wide, 30-day NO_X emission rate limit of 0.102 lb/MMBtu, and daily, mass-based limits of 17,912 and 17,732 lbs NO_X /day for Units 1 and 2, respectively. In the interest of consistency, EPA is finalizing the limits derived from our original methodology rather than the alternate limits proposed by Montour. Additionally, because EPA's limits are in line with, and in fact very slightly higher than what Montour proposed, EPA is not evaluating the remainder of Montour's technical analysis.

Comment: Several commenters assert that because achieving compliance with MATS has a negative effect on NO_X reduction efficiency, EPA should not have considered years prior to MATS requirements, and that the limits are therefore too stringent.

Response: EPA recognizes the co-benefits of SCRs regarding the oxidation and ultimate removal of mercury from flue gas. Commenters suggest that there is a trade-off between NO_X and mercury removal, resulting in higher NO_X rates to ensure sufficient mercury capture. EPA has conducted analysis to evaluate this contention in a previous rulemaking. Specifically, to respond to comments received on the proposed CSAPR Update, EPA examined ozone-season NO_X rates from 86 units subject to the MATS rule with SCR and rates below 0.12 lbs NO_X /MMBtu in 2015 (*i.e.,* units that were removing the necessary mercury while operating their SCRs during the 2015 ozone season). EPA selected the rate cut-off of 0.12 lbs NO_X /mmBtu to clearly identify units that were operating their SCR. EPA found that the average 2015 NO_X rate at these 86 units was 0.072 lb/MMBtu. The average rate for these same units in previous years was 0.080 and 0.078 lb/MMBtu for 2014 and 2013, which was prior to the MATS compliance date when the units would have only needed to optimize operations for purposes of NO_X removal rather than mercury removal. The 2014 and 2013 rates were each statistically significantly higher than the rate in 2015 when these units were complying with the MATS rule (Student's t-test probability (p) <0.03 and 0.03). Based on the CSAPR Update analysis, which is included in the docket for this rulemaking,[46] EPA concludes that units are able to simultaneously comply with MATS (*i.e.,* remove mercury from flue gas) while maintaining or even lowering their NO_X rates, and that the comment therefore does not provide a sufficient basis for EPA to exclude data from years before MATS implementation from the analysis conducted for this rule.

Comment: Several commenters note the role PJM plays in directing the units' dispatch and then assert various implications concerning the feasibility or cost of the proposed emissions limits. For example, Talen states that “PJM retains complete and unilateral discretion for calling the units to run at certain load profiles. In addition to directing Montour SES when to start up the units, PJM's typical dispatch also includes the lowering of the unit output down to minimum load during off-peak periods daily.” Talen further states that “PJM dispatch information can dictate the ramp rate of the unit after a startup. It is not wholly in Montour SES's control to adjust unit operation to fit EPA's proposed model.” Homer City states that “operations today are, in large part, determined by PJM and are beyond control of the source operators” and that the proposed emissions limits would not accommodate emissions during “startups, shutdowns, and low-load operations directed by PJM.” Homer City also asserts that sometimes “[PJM's] direction requires Homer City to operate at levels . . . which [do] not allow for operation of the SCR.” Key-Con states that, “in general” dispatch of units in the PJM market “is controlled by PJM, not the EGU owner or operator.” Key-Con suggests EPA has assumed that unit owners can choose to ignore PJM's dispatch instructions. Key-Con also states that the proposed emission rates “will require Key-Con to forfeit most dispatch opportunities at lower electrical loads as directed by PJM and suffer resultant revenue impacts in order to maintain compliance with the limits.”

Response: The fact that PJM generally directs the day-to-day and hour-to-hour dispatch of the units subject to this rule is not in dispute, and any comments suggesting that EPA has assumed otherwise mischaracterize the proposal.[47] However, in EPA's view, the consequences that commenters assert could result from requirements to follow PJM's dispatch instructions are unrealistic because the commenters largely fail to acknowledge sources' considerable ability to influence those instructions through the offer prices and operating parameters that the sources provide to PJM for use in PJM's decision-making process. In particular, EPA does not agree with commenters' suggestions that PJM's dispatch instructions would create a material obstacle to the sources' efforts to comply with the limits in an economic manner. Rather, EPA believes it is entirely reasonable to assume, first, that the source owners will have the opportunity to consider their emission limits when developing the information they supply to PJM for use in PJM's decision-making process and, second, that PJM's subsequent dispatch instructions will consider the information supplied by the owners when determining the dispatch instructions. In other words, contrary to

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the commenter's suggestions, EPA believes that the sources' role as suppliers of inputs to PJM's decision-making process means that the sources in fact are well positioned to prevent PJM's dispatch instructions from interfering with the sources' compliance strategies.

A few examples of the information that sources can specify to PJM for use in PJM's decision-making illustrate how the sources covered by this rule could cause PJM to issue dispatch instructions that are generally compatible with what the source owners consider necessary to facilitate effective SCR operation. First, the operating parameters that a source can specify include “Economic Min (MW),” representing the owner's specification of “the minimum energy available, in MW, from the unit for economic dispatch” under non-emergency conditions.[48] If a source is concerned about the possibility that PJM otherwise might direct the unit to run extensively—for example, during all or most overnight off-peak hours—at low load levels that would be insufficient to maintain SCR inlet temperatures high enough for effective SCR performance, the source can avoid that outcome by specifying higher values for Economic Min (MW). Second, the operating parameters include “Ramp Rate (MW/Min),” representing the default rate, in MW per minute, for increasing or decreasing a unit's output.[49] If a source is concerned about the possibility that PJM would otherwise frequently direct the unit to increase or decrease its output at rates that would cause difficulty in sustaining consistent SCR performance, the source can avoid that outcome by specifying lower values for Ramp Rates. Third, sources can submit cost-based or price-based values for a variety of parameters associated with unit start-ups, such as “Cold Startup Cost,” “Intermediate Startup Cost,” and “Hot Startup Cost,” representing the cost-based or price-based offers for the source's compensation for each start-up, differentiated according to the unit's temperature before the start-up.[50] If a source believes that its compliance strategy should include efforts to reduce start-up emissions by substituting gas or oil for some of the coal that would otherwise be combusted during the start-up process, the source generally can revise its offered Startup Cost values to reflect any resulting changes in start-up fuel cost.

EPA recognizes that under certain emergency system conditions, PJM may issue dispatch instructions that reflect various “emergency” parameters rather than the parameters discussed above that would be used for economic dispatch under more typical system conditions. EPA further recognizes that dispatch instructions issued by PJM in an emergency could theoretically require a unit to temporarily operate in a manner that precludes effective SCR operation until the emergency ends or until PJM can implement alternative measures to address the emergency. EPA is also aware that PJM's procedures include lead times that may affect how soon sources could change certain elements of the information they provide to PJM for use in PJM's decision-making. However, EPA believes these considerations are sufficiently addressed by the fact that the emission rate limits established in this rule are defined as 30-day rolling averages and the fact that EPA is not making the requirements established in this rule effective until 180 days after the rule's effective date.

EPA found no information in the comments indicating that the sources could not improve their abilities to run their SCRs continuously or at improved overall emissions rates by taking advantage of opportunities to optimize the values they provide to PJM for offer prices and operating parameters, potentially including but not limited to Economic Min (MW), Ramp Rate (MW/Min), and Cold, Intermediate, and Hot Startup Cost.[51] Rather, in suggesting that PJM's dispatch instructions could conflict with the proposed emission limits, commenters relied solely on the fact that the sources generally must comply with PJM's instructions once the instructions are issued, with no discussion of the process by which PJM determines what its instructions should be and no discussion of the sources' own opportunities to influence that process.[52]

Finally, EPA notes that changes in the emissions and operating data reported by the Conemaugh and Keystone units for the first half of the 2022 ozone season relative to the data reported by these units for the 2021 ozone season appear to corroborate EPA's understanding that sources have the ability to influence PJM's dispatch decisions. During the periods of the 2021 ozone season when these units operated, a frequent operating pattern for each of the units was to cycle between a full load level of approximately 900 MW during daytime peak hours and a lower load level of approximately 440 MW during overnight off-peak hours, running their SCRs at the higher daytime loads and turning off their SCRs at the lower nighttime loads. During the periods of the first half of the 2022 ozone season when the units operated, while they continued to display the same general daytime-nighttime cycling pattern, the load levels to which they cycled down overnight were higher than in 2021, apparently producing flue gas temperatures sufficient to allow the units to run their SCRs overnight. Specifically, during May and June 2022 the Conemaugh units generally cycled down to a load level of approximately 545 MW, and the Keystone units generally cycled down to a load level of approximately 700 MW. EPA believes the reason for the change in overnight load levels is that the sources must have provided higher values of Economic Min (MW) to PJM for use in making dispatch decisions during the 2022 ozone season. Taking such a step would have increased the likelihood that the units would be given dispatch instructions that would allow them to run their SCRs continuously and would have been a rational response by the sources to the higher reported NO_X allowance prices during the 2022 ozone season. [53] In summary, EPA finds these comments unpersuasive when appropriately evaluated in the context of sources' extensive ability to influence PJM's decision-making, which is unchallenged in the comments.

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IV. EPA's Final RACT Analysis and Emission Limits

After consideration of all public comments, the EPA is establishing the 30-day NO_X Emission Rate Limits in Table 5 and Daily NO_X Mass Emission Limits in Table 8 for the four facilities covered by this FIP to meet the statutory requirement to implement RACT for the 1997 and 2008 ozone NAAQS.

Table 5—Facility-Wide 30-Day Rolling Average NO_X Emission Rate Limits

Facility name	Facility-wide 30-day average rate limit (lb/MMBtu)
Conemaugh	0.072
Homer City	0.096
Keystone	0.075
Montour	0.102

The limits in Table 5 are based on a 30-day rolling average, and apply at all times, including during operations when exhaust gas temperatures at the SCR inlet are too low for the SCR to operate, or operate optimally. As discussed in the proposal and in response to comments, a 30-day average “smooths” operational variability by averaging the current value with the prior values over a rolling 30-day period to determine compliance. While some period of lb/MMBtu values over the target rate can occur without triggering a violation, they must be offset by corresponding periods where the lb/MMBtu rate is lower than the compliance rate (*i.e.,* the 30-day rolling average rate).

To calculate the final 30-day rates, EPA used the same weighted rate methodology from the proposal, with three key changes. The data underlying the weighted rates calculation for each unit is shown in Table 6 below.

Table 6—Unit-Specific Weighted Rates Data

Facility name	Unit	SCR on rate	SCR on weight (%)	SCR off rate	SCR off weight (%)	Weighted rate	Facility-wide average weighted rate
Conemaugh	1	0.070	98.5	0.255	1.5	0.073	0.072
Conemaugh	2	0.070	99.8	0.258	0.2	0.071	
Homer City	1	0.103	99.8	0.341	0.2	0.103	0.096
Homer City	2	0.087	99.3	0.322	0.7	0.088	
Homer City	3	0.096	99.6	0.292	0.4	0.097	
Keystone	1	0.041	86.7	0.309	13.3	0.076	0.075
Keystone	2	0.043	88.4	0.312	11.6	0.074	
Montour	1	0.045	81.5	0.384	18.5	0.108	0.102
Montour	2	0.047	85.7	0.396	14.3	0.096	

First, using information from the comments, EPA revised the SCR thresholds for certain sources. As explained previously, these thresholds are applied to the historical data set for the purpose of calculating SCR-on and SCR-off rates and weights to calculate the final weighted rates. EPA revised the thresholds for Homer City Units 1 and 2 and Montour Units 1 and 2. Homer City did not provide a revised threshold for Unit 3, so the same threshold from the proposal was used for the final calculation for that unit. Key-Con also did not provide updated thresholds for Keystone and Conemaugh, though their thresholds from the proposal were based on comments from Key-Con on the recommendation submitted to EPA by the Ozone Transport Commission (OTC) under CAA § 184(c).[54] [55] Table 7 of this preamble shows the thresholds used for the final calculation. As previously discussed, based on additional information received during the public comment period, the thresholds for Homer City Units 1 and 2 increased slightly, while the thresholds for Montour increased more significantly, as compared to the proposal.

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Table 7—SCR Thresholds Used In Weighted Rates Analysis

[Proposal vs. final]

Facility name	Unit	SCR threshold, proposal (MW)	SCR threshold, final (MW)
Conemaugh	1	450	450
Conemaugh	2	450	450
Homer City	1	320	340
Homer City	2	320	335
Homer City	3	320	320
Keystone	1	660	660
Keystone	2	660	660
Montour	1	380	440
Montour	2	380	440

The threshold changes result in some changes to the data underlying the weighted rate calculation for Homer City Units 1 and 2 and Montour Units 1 and 2 from the proposal.[56] The changes to the SCR thresholds changed the SCR-on and -off rates for these units very slightly, as some hours went from being classified as SCR-on to SCR-off. The SCR-on and -off rates for the other units do not change from the proposal, and EPA is still using the rate based on the EGU's third-best ozone season average from 2003 to 2021 (second-best ozone season average for Conemaugh due to its more limited years of SCR data as compared to other units). The threshold changes altered the SCR-on and -off weights slightly for the Homer City units and substantially for the Montour units.

Second, while EPA is retaining the use of the third-best weight (the ozone season in which the EGU had its third highest proportion of heat input spent above the SCR threshold) from the period 2011 to 2021 for Homer City, Keystone, and Montour, EPA is using the second-best weight (the ozone season in which the EGU had its second highest proportion of heat input spent above the SCR threshold) for Conemaugh. As discussed previously in this action and in the proposal, Conemaugh installed its SCR much later than the other sources. In response to comments pointing out that Conemaugh's proposed limit was the highest despite having the newest SCR as well as to account for the more limited set of ozone seasons from which to draw data, the Agency believes it is reasonable to use the second-best weight instead of the third-best. EPA believes that the atypical result pointed out by the commenter stems mainly from the fact that using a third-best weight from a 7-year data set (as opposed to a third-best weight from an 11-year data set used for the other sources with more years of SCR data) would be more analogous to a mean rate, rather than the lowest rate the source was capable of achieving as RACT requires. Given EPA's determination, informed by the Court decision, that RACT should represent a better rate than a mean rate, we believe that for Conemaugh, the second-best weight would provide a more comparable weight, while still excluding the low end. This results in a tightening of Conemaugh's final limit, as compared to the proposal. EPA still believes it is reasonable to use the time period 2011 to 2021 from which to draw the weights for Homer City, Keystone, and Montour for the final limit. EPA re-examined the occurrence of cycling at these facilities and found that the drop in time spent above the SCR threshold begins within this time period for these sources.

Third, as discussed in section III of this preamble, because of the unit-specific nature of EPA's weighted rate analysis, the EPA expects that the unit-specific rates already represent RACT for each unit, and that the most appropriate basis for a facility-wide average would be the weighted rates for each of the units at the facility. Therefore, EPA is calculating the final facility-wide 30-day limits as an arithmetic average of the results of the weighted rates calculation for each unit at the facility, instead of applying the best unit-specific weighted rate facility-wide.

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Table 8—Revised Unit-Specific Daily NO_X Mass Emissions Limits

Facility name	Unit	Unit-specific mass limit (lb/day)
Conemaugh	1	14,308
Conemaugh	2	14,308
Homer City	1	15,649
Homer City	2	15,649
Homer City	3	16,727
Keystone	1	15,691

Facility name	Unit	Unit-specific mass limit (lb/day)
Keystone	2	15,691
Montour	1	17,912
Montour	2	17,721

The final daily limits in Table 8, which complement the facility-wide 30-day rate and further ensure RACT is applied continuously, are calculated using the same methodology as the proposal but with the updated final 30-day limits as shown in Table 5 of this preamble. The final 30-day limits are multiplied by each unit's maximum permitted heat input (in MMBtu/hr) by 24 hours.

V. Final Action

Based on the considerations outlined at proposal, consideration of all public comments, and for the reasons described in this action, EPA is establishing the 30-day NO_X emission rate limits in Table 5 of this preamble, Daily NO_X mass emission limits in Table 8 of this preamble, and accompanying regulatory language added to 40 CFR 52.2065 (https://www.ecfr.gov/current/title-40/section-52.2065), as major stationary source NO_X RACT requirements for the 1997 and 2008 ozone NAAQS at four facilities in Pennsylvania: Conemaugh; Homer City; Keystone; and Montour.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders (https://www.epa.gov/laws-regulations/laws-and-executive-orders).*

A. Executive Order 12866 (/executive-order/12866): Regulatory Planning and Review and Executive Order 13563 (/executive-order/13563): Improving Regulation and Regulatory Review

This final action is a rule of particular applicability and therefore is exempt from Office of Management and Budget (OMB) review.

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act (PRA).[57] A "collection of information" under the PRA means "the obtaining, causing to be obtained, soliciting, or requiring the disclosure to an agency, third parties or the public of information by or for an agency by means of identical questions posed to, or identical reporting, recordkeeping, or disclosure requirements imposed on, *ten or more persons,* whether such collection of information is mandatory, voluntary, or required to obtain or retain a benefit." [58] Because this proposed rule includes RACT reporting requirements for four facilities, the PRA does not apply.

C. Regulatory Flexibility Act

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action does not affect small governmental jurisdictions or small organizations, and the affected entities are not small businesses as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201 (https://www.ecfr.gov/current/title-13/section-121.201). Therefore, this action will not impose any requirements on small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531-1538 (https://www.govinfo.gov/link/uscode/2/1531), and does not significantly or uniquely affect small governments.

E. Executive Order 13132 (/executive-order/13132): Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175 (/executive-order/13175): Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (/executive-order/13175), entitled "Consultation and Coordination with Indian Tribal Governments," requires the EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." [59] This rule does not have tribal implications, as specified in Executive Order 13175 (/executive-order/13175). It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 (/executive-order/13175) does not apply to this rule.

G. Executive Order 13045 (/executive-order/13045): Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 (/executive-order/13045) as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the Executive Order. This action is not subject to Executive Order 13045 (/executive-order/13045) because it implements a previously promulgated health-based Federal standard. Further, the EPA believes that the ozone-related benefits from this final rule will further improve children's health.

H. Executive Order 13211 (/executive-order/13211): Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (/executive-order/13211) (66 FR 28355 (/citation/66-FR-28355) (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866 (/executive-order/12866).

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

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J. Executive Order 12898 (/executive-order/12898): Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (/executive-order/12898) establishes Federal executive policy on environmental justice.[60] Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the United States.

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (/executive-order/12898). EPA reviewed the Regulatory Impact Analysis (RIA) prepared for the recently proposed 2015 Ozone NAAQS transport FIP, and in particular the Ozone Exposure Analysis at section 7.4 of the RIA.[61] Although that analysis projected reductions in overall AS-MO3 ozone concentrations in each state for all affected demographic groups resulting from newly proposed limits on EGUs and non-EGUs (See Figure 7-3 of the RIA), it also found that emission reductions from only EGUs would result in national reductions in AS-MO3 ozone concentrations for all demographic groups analyzed (See Figure 7-2 of the RIA). In summation, based on the analysis contained in that RIA, EPA has concluded that the FIP is expected to lower ozone in many areas, including residual ozone nonattainment areas, and thus mitigate some pre-existing health risks of ozone across all populations evaluated (RIA, p. 7-32). Further, EPA reviewed an analysis of vulnerable groups near the Conemaugh, Homer City, and Keystone EGUs found in the TSD for EPA's proposed disapproval of the SO_2 attainment plan for the Indiana, PA SO_2 nonattainment area.[62]

K. Congressional Review Act (CRA)

This rule is exempt from the CRA because it is a rule of particular applicability.

VII. Petitions for Judicial Review

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by October 31, 2022. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action.

This action setting RACT limits for certain EGUs in Pennsylvania may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52 (https://www.ecfr.gov/current/title-40/part-52)

- Environmental protection
- Air pollution control
- Continuous emission monitoring
- Electric power plants
- Incorporation by reference
- Nitrogen oxides
- Ozone
- Reporting and recordkeeping requirements

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, the EPA amends 40 CFR part 52 (https://www.ecfr.gov/current/title-40/part-52) as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 (https://www.govinfo.gov/link/uscode/42/7401) *et seq.*

Subpart NN—Pennsylvania

2. Section 52.2065 is added to subpart NN to read as follows:

§ 52.2065 Federal implementation plan addressing reasonably available control technology requirements for certain sources.

(a) *Applicability*. This section shall apply to Conemaugh, Homer City, Keystone, and Montour, as defined in this section, as well as any of their successors or assigns. Each of the four listed facilities are individually subject to the requirements of this section.

(b) *Effective date*. The effective date of this section is September 30, 2022.

(c) *Compliance date*. Compliance with the requirements in this section shall commence on March 29, 2023, except the Facility-wide 30-Day Rolling Average NO_X Emission Rate Limit requirement in (f)(1) of this section will commence for the Facility on the day that Facility has operated for thirty (30) Operating Days after, and possibly including, the compliance date of March 29, 2023.

(d) *General provisions*. This section is not a permit. Compliance with the terms of this section does not guarantee compliance with all applicable Federal, state, or local laws or regulations. The emission rates and mass emissions limits set forth in this section do not relieve the facility from any obligation to comply with other State and Federal requirements under the Clean Air Act, including the Facility's obligation to satisfy any State requirements set forth in the applicable SIP.

(e) *Definitions*. Every term expressly defined by this section shall have the meaning given to that term within this section. Every other term used in this section that is also a term used under the Act or in Federal regulations in this chapter implementing the Act shall mean in this section what such term means under the Act or the regulations in this chapter.

CEMS or *Continuous Emission Monitoring System,* means, for obligations involving the monitoring of NO_X emissions under this section, the devices defined in 40 CFR 72.2 (https://www.ecfr.gov/current/title-40/section-72.2) and installed and maintained as required by 40 CFR part 75 (https://www.ecfr.gov/current/title-40/part-75).

Clean Air Act or *Act* means the Federal Clean Air Act, 42 U.S.C. 7401-7671q (https://www.govinfo.gov/link/uscode/42/7401), and its implementing regulations in this chapter.

Conemaugh means, for purposes of this section, Keystone Conemaugh Project LLC's Conemaugh Generating Station consisting of two coal-fired units designated as Unit 1 (8,280 MMBtu/hr) and Unit 2 (8,280 MMBtu/hr), located in West Wheatfield Township, Indiana County, Pennsylvania.

Day or *daily* means calendar day unless otherwise specified in this section.

EGU means electric generating unit.

EPA means the United States Environmental Protection Agency.

Facility means each of the following as defined in this section: Conemaugh; Homer City; Keystone; and Montour.

Facility-wide 30-Day Rolling Average NO_X Emission Rate for the Facility shall be expressed in lb/MMBtu and calculated in accordance with the following procedure: first, sum the total pounds of NO_X emitted from all Units during the current Operating Day and the previous twenty-nine (29) Operating Days; second, sum the total heat input from all Units in MMBtu during the current Unit Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of NO_X emitted *from all Units* during the thirty (30) Operating Days by the total heat input during the thirty 🗋 (30) Operating Days. A new Facility-wide 30-Day Rolling Average NO_X Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average NO_X Emission Rate shall include all emissions that occur during all periods within any Operating Day, including, but not limited to, emissions from startup, shutdown, and malfunction.

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Fossil fuel means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, fuel oil, or natural gas.

Homer City means, for purposes of this section, Homer City Generation LP's Homer City Generating Station consisting of three coal-fired units designated as Unit 1 (6,792 MMBtu/hr), Unit 2 (6,792 MMBtu/hr), and Unit 3 (7,260 MMBtu/hr), located in Center Township, Indiana County, Pennsylvania.

Keystone means, for purposes of this section, Keystone Conemaugh Project LLC's Keystone Generating Station consisting of two coal-fired units designated as Unit 1 (8,717 MMBtu/hr) and Unit 2 (8,717 MMBtu/hr), located in Plumcreek Township, Armstrong County, Pennsylvania.

lb/MMBtu means one pound per million British thermal units.

Montour means, for purposes of this section, Talen Energy Corporation's Montour Steam Electric Station consisting of two coal-fired units designated as Unit 1 (7,317 MMBtu/hr) and Unit 2 (7,239 MMBtu/hr), located in Derry Township, Montour County, Pennsylvania.

" *NO_X* " means oxides of nitrogen, measured in accordance with the provisions of this section. " *NO_X emission rate* " means the number of pounds of NO_X emitted per million British thermal units of heat input (lb/MMBtu), calculated in accordance with this section.

Operating day means any calendar day on which a Unit fires Fossil Fuel.

Title V Permit means the permit required for major sources pursuant to Subchapter V of the Act, 42 U.S.C. 7661-7661e (https://www.govinfo.gov/link/uscode/42/7661).

Unit means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for production of electricity. An electric steam generating station may be comprised of one or more Units.

Unit-specific daily NO_X mass emissions shall be expressed in lb/day and calculated as the sum of total pounds of NO_X emitted from the Unit during the Unit Operating Day. Each Unit-specific Daily NO_X Mass Emissions shall include all emissions that occur during all periods within any Operating Day, including emissions from startup, shutdown, and malfunction.

(f) *NO_X emission limitations.* (1) The Facility shall achieve and maintain their Facility-wide 30-Day Rolling Average NO_X Emission Rate to not exceed their Facility limit in Table 1 to this paragraph (f)(1).

Table 1 to Paragraph (f)(1)—Facility-Wide 30-Day Rolling Average NO $_X$ Emission Rate Limits

Facility	Facility-wide 30-day rolling average NO $_X$ emission rate limit (lb/MMBtu)
Conemaugh	0.072
Homer City	0.096
Keystone	0.075
Montour	0.102

(2) The Facility shall achieve and maintain their Unit-specific Daily NO_X Mass Emissions to not exceed the Unit-specific limit in Table 2 to this paragraph (f)(2).

Table 2 to Paragraph (f)(2)—Unit-Specific Daily NO $_X$ Mass Emissions Limits

Facility	Unit	Unit-specific daily NO $_X$ mass emissions limit (lb/day)
Conemaugh	1	14,308
Conemaugh	2	14,308
Homer City	1	15,649
Homer City	2	15,649
Homer City	3	16,727
Keystone	1	15,691
Keystone	2	15,691
Montour	1	17,912
Montour	2	17,721

(g) *Monitoring of NO_X* emissions. (1) In determining the Facility-wide 30-Day Rolling Average NO_X Emission Rate, the Facility shall use CEMS in accordance with the procedures of 40 CFR parts 60 (https://www.ecfr.gov/current/title-40/part-60/appendix-Appendix%20F%20to%20Part%2060) and 75, appendix F (https://www.ecfr.gov/current/title-40/part-75/appendix-Appendix%20F%20to%20Part%2075), Procedure 1.

(2) For purposes of calculating the Unit-specific Daily NO_X Mass Emissions Limits, the Facility shall use CEMS in accordance with the procedures at 40 CFR part 75 (https://www.ecfr.gov/current/title-40/part-75). Emissions rates, mass emissions, and other quantitative standards set by or under this section must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. The Facility shall round the fourth significant digit to the nearest third significant digit, or the sixth significant digit to the nearest fifth significant digit, depending upon whether the limit is expressed to three or five significant digits. For example, if an actual emission rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an emission rate of 0.100, and if an actual emission rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an emission eate of 0.100. The Facility shall report data to the number of significant digits in which the standard or limit is expressed.

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(h) *Recordkeeping and periodic peporting*. (1) The Facility shall electronically submit to EPA a periodic report, within thirty (30) Days after the end of each six-month reporting period (January through June, July through December in each calendar year). The portion of the periodic report containing the data required to be reported by this paragraph (h) shall be in an unlocked electronic spreadsheet format, such as Excel or other widely-used software, and contain data for each Operating Day during the reporting period, including, but not limited to: Facility ID (ORISPL); Facility name; Unit ID; Date; Unit-specific total Daily Operating Time (hours); Unit-specific Daily NO_X Mass Emissions (lbs); Unit-specific total Daily Heat Input (MMBtu); Unit-specific Daily NO_X Emission Rate (lb/MMBtu); Facility-wide 30-Day Rolling Average NO_X Emission Rate (lb/MMBtu); Owner; Operator; Representative (Primary); and Representative (Secondary). In addition, the Facility shall maintain the following information for 5 years from the date of creation of the data and make such information available to EPA if requested: Unit-specific hourly heat input, Unit-specific hourly ammonia injection amounts, and Unit-specific hourly NO_X emission rate.

(2) In any periodic report submitted pursuant to this section, the Facility may incorporate by reference information previously submitted to EPA under its Title V permitting requirements, so long as that information is adequate to determine compliance with the emission limits and in the same electronic format as required for the periodic report, and provided that the Facility attaches the Title V Permit report (or the pertinent portions of such report) and provides a specific reference to the provisions of the Title V Permit report that are responsive to the information required in the periodic report.

(3) In addition to the reports required pursuant to this section, if the Facility exceeds the Facility-wide 30-day rolling average NO_X emission limit on three or more days during any 30-day period, or exceeds the Unit-specific daily mass emission limit for any Unit on three or more days during any 30-day period, the Facility shall electronically submit to EPA a report on the exceedances within ten (10) business days after the Facility knew or should have known of the event. In the report, the Facility shall explain the cause or causes of the exceedances and any measures taken or to be taken to cure the reported exceedances or to prevent such exceedances in the future. If, at any time, the provisions of this section are included in Title V Permits, consistent with the requirements for such inclusion in this section, then the deviation reports required under applicable Title V regulations shall be deemed to satisfy all the requirements of this paragraph (h)(3).

(4) Each report shall be signed by the Responsible Official as defined in Title V of the Clean Air Act, or his or her equivalent or designee of at least the rank of Vice President. The signatory shall also electronically submit the following certification, which may be contained in a separate document:

“This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.”

(5) Whenever notifications, submissions, or communications are required by this section, they shall be made electronically to the attention of the Air Enforcement Manager via email to the following address: *R3_ORC_mailbox@epa.gov (mailto:R3_ORC_mailbox@epa.gov).*

Footnotes

1. See 51 Pa.B. 5834, September 11, 2021 (Keystone); 51 Pa.B. 6259, October 2, 2021 (Conemaugh); 51 Pa.B. 6558, October 16, 2021 (Homer City); 51 Pa.B. 6930, November 6, 2021 (Montour); Allegheny County Health Department Public Notices, December 2, 2021 (Cheswick).
Back to Citation

2. See Memo, dated December 9, 1976, from Roger Strelow, Assistant Administrator for Air and Waste Management, to Regional Administrators, “Guidance for Determining Acceptability of SIP Regulations in Non-Attainment Areas,” p. 2, available at https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19761209_strelow_ract.pdf (https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19761209_strelow_ract.pdf) (Strelow Memo), and 44 FR 53761 (/citation/44-FR-53761), at 53762, footnote 2 (September 17, 1979).
Back to Citation

3. See the Excel spreadsheet entitled “PA-MD-DE SCR unit data 2002-2020.xlsx” in the docket for this action.
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4. This point is not applicable to the Conemaugh facility where SCR was installed much later than other facilities at issue in this rule. According to Key-Con's comment letter, “KEY-CON Management understood that compliance with the near-future MATS Rule and PADEP RACT II Rule would preclude unit operations that bypassed the SCRs at both stations.” See Key-Con comments at 10.
Back to Citation

5. PJM is a regional transmission organization (RTO) or grid operator which provides wholesale electricity throughout 13 states and the District of Columbia.
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6. U.S. Energy Information Administration, “Electric Power Annual 2020,” Table 3.1.A. Net Generation by Energy Source, https://www.eia.gov/electricity/annual/ (https://www.eia.gov/electricity/annual/).
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7. U.S. EPA, “EPA Alternative Control Techniques Document for NO_X Emissions from Utility Boilers” EPA-453/R-94-023, March 1994, p. 5-119, https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000INPN.txt (https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000INPN.txt).

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8. See Chapter 2, subsection 2.2.2 of the SCR Cost Manual, 7th Edition, available at https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf).
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9. EPA is not revising the TSD. Any new technical analysis will be discussed directly in section III (EPA's Response to Comments) of this preamble.
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10. See section C of the TSD for the proposed action.
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11. The decreasing competitiveness of Pennsylvania's coal units is illustrated by the fact that their share of the state's total generation has declined from about 60% in 2001 to roughly 10% in 2021. See Energy Information Administration. Form EIA-923, Power Plant Operations Report (2001-2021).
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12. See 87 FR 31806 (/citation/87-FR-31806) (May 25, 2022).
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13. See 87 FR 31807 (/citation/87-FR-31807) (May 25, 2022).
14. Title V Permit maximum heat input rates.
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15. Memo, dated December 9, 1976, from Roger Strelow, Assistant Administrator for Air and Waste Management, to Regional Administrators, "Guidance for Determining Acceptability of SIP Regulations in Non-Attainment Areas," p. 2, available at https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19761209_strelow_ract.pdf (https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19761209_strelow_ract.pdf) and 44 FR 53762 (/citation/44-FR-53762), footnote 2 (September 17, 1979) (Strelow Memo). See also Sierra Club v. EPA, 972 F.3d 290.
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16. Id.
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17. 57 FR 55620 (/citation/57-FR-55620), November 25, 1992
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18. See 25 Pa Code §§ 129.94 and 129.98, which allow sources which cannot meet a presumptive RACT limit to average with lower emitting sources, provided that aggregate emissions do not exceed what would have been allowed under the presumptive limits.
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19. 80 FR at 12278-79 ("states may demonstrate as part of their NO_X RACT SIP submittal that the weighted average NO_X emission rate from all sources in the nonattainment area subject to RACT meets NO_X RACT requirements"). This portion of the 2008 ozone SIP requirements rule was challenged, with petitioners arguing that such a rule violated the Clean Air Act because the statute at § 182(b)(2) requires each individual source to meet the NO_X RACT requirement. The D.C. Circuit rejected this argument, finding that the Clean Air Act "does not specify that `each one of' the individual sources within the category of `all' `major sources' must implement RACT." South Coast Air Quality Mgmt Dist. v. EPA, 882 F.3d 1138, 1154 (D.C. Cir. 2018).
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20. See TSD for proposed FIP at 16-18.
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21. Reagent prices have decreased since publication of the NPRM, from an average of $1515/ton anhydrous ammonia to slightly less than $1400/ton. See appendix 3 of the TSD for this action, and https://mymarketnews.ams.usda.gov/filerepo/sites/default/files/3195/2022-07-28/614317/ams_3195_00065.pdf (https://mymarketnews.ams.usda.gov/filerepo/sites/default/files/3195/2022-07-28/614317/ams_3195_00065.pdf).
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22. See Id. at 15.
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23. See Id. at 19.
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24. E.P.A., State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 FR 18 (/citation/57-FR-18),070 (/citation/57-FR-070), 18 (/citation/57-FR-18),073 (/citation/57-FR-073) (proposed April 28, 1992) (first introducing RACT as a standard to regulate emissions from existing sources).
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25. Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone (NO_X SIP Call), 63 FR 57356 (/citation/63-FR-57356) (October 27, 1998) (codified in relevant part at 40 CFR 51.121 (https://www.ecfr.gov/current/title-40/section-51.121) and 51.122 (https://www.ecfr.gov/current/title-40/section-51.122)).
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26. See S&P Global Capital IQ, capitaliq.spglobal.com (subscription required).
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27. Per condition E.10 of the draft permit for Conemaugh, their target was 0.05 lb NO_X /MMBtu
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28. Commenters assert that 2020 and 2021 were excluded due to low electricity demand and lack of coal supply, respectively.
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29. PADEP's proposed RACT limit.
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30. P. 11 of Key-Con's July 11, 2022 comments.
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31. As noted in the NPRM, the limits proposed for Conemaugh were based on the second-best ozone season, since Conemaugh's SCR was only installed in late 2014 and EPA therefore doesn't have the same volume of operating data as for the other sources.
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32. The proposed limit used the second best rate and the third best weight.
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33. For examples of this SCR-off operation, see the xl spreadsheet in the docket entitled "KEY_Hourly emissions and operating data 2017-2020_06-24-21." For Keystone Unit 1, see February 5th to 28th, 2017, and for Unit 2 see October 1 through 30th, 2017. For Conemaugh, see the spreadsheet in the docket entitled

"CON_Hourly emissions and operating data 2017-2020_6-24-21." For Unit 1, see January 21 through 23rd, 2017 and for Unit 2 see April 15th through 17th, 2017.
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34. See "Attachment 3-1 NO_X Rate Development in EPA Platform v6" for EPA's Power Sector Modeling Platform (IPM) at https://www.epa.gov/system/files/documents/2022-02/attachment-3-1-nox-rate-development-in-epa-platform-v6-summer-2021-reference-case.pdf (https://www.epa.gov/system/files/documents/2022-02/attachment-3-1-nox-rate-development-in-epa-platform-v6-summer-2021-reference-case.pdf).
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35. See document ID EPA-R03-OAR-2022-0347-0067 in the docket for this action at www.regulations.gov (http://www.regulations.gov).
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36. EPA has not yet evaluated and is not pre-determining the approvability Pennsylvania's ultimate SIP revisions, which were submitted on May 26, 2020 and June 9, 2022.
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37. Sierra Club at 309.
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38. The proposal erroneously published the effective date of the rule as June 24, 2022 and not as an editorial note that the rule would be effective 30 days after the publication of the final rule. See 87 FR 31813 (/citation/87-FR-31813).
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39. See "Memo to Docket—Availability of Additional Information," document number EPA-R03-OAR-2022-0347-0060.
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40. See https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf) at 16.
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41. 972 F.3d at 302.
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42. Delaware Administrative Code, Title 7 Natural Resources & Environmental Control, 1100 Air Quality Management Section, 1146 "Electric Generating Unit (EGU) Multi-Pollutant Regulation".
Maryland—Code of Maryland Regulations (COMAR), Title 26 Department of the Environment, Subtitle 11 Air Quality, Chapter 38, "Control of NO_X Emissions from Coal-Fired Electric Generating Units".
New Jersey State Department of Environmental Protection, New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 19, "Control and Prohibition of Air Pollution from Oxides of Nitrogen".
"Coal-Fired Power Plant Enforcement" US EPA, retrieved August 2022. See https://www.epa.gov/enforcement/coal-fired-power-plant-enforcement (https://www.epa.gov/enforcement/coal-fired-power-plant-enforcement).
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43. "Custom Data Download" US EPA Clean Air Markets Program Data, retrieved August 2022, see https://campd.epa.gov/data/custom-data-download (https://campd.epa.gov/data/custom-data-download).
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44. See "Keystone winter-time SCR use unit 1.xlsx" in the docket for this action.

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45. Id.
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46. See MATS Compliance Impact on SCR Control Rates.xlsx.
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47. For example, EPA views Key-Con's extended argument that sources do not have incentives to violate PJM's dispatch instructions not as an attempt to rebut anything EPA actually said in the proposal but rather as the creation and subsequent rebuttal of Key-Con's own strawman.
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48. See the PJM Markets Gateway User Guide (PJM Guide), available at https://pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx (https://pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx), at 35.
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49. See PJM Guide at 35. Different Ramp Rate values can be specified for different portions of a unit's overall load output range, and different values can be specified for output increases and output decreases. Id. at 38-40.
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50. See PJM Guide at 51-53.
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51. In addition to Economic Min (MW), sources can also specify "Economic Max (MW)," representing the owner's specification of the maximum energy available from the unit for economic dispatch under non-emergency conditions. See PJM Guide at 35. PJM evaluates whether the ratio of the value submitted for Economic Max (MW) to the value submitted for Economic Min (MW)—known as the "Turn Down Ratio," see PJM Guide at 103, falls below a default floor value established by PJM for that type of unit. If so, the source must obtain PJM's approval for the submitted Economic Min and Economic Max parameter values (i.e., an "exception" to the Turn Down Ratio default floor value) by providing additional information to justify the source's submitted values. In an attachment to its comments, Key-Con has indicated its awareness of the availability of such exceptions and its expectation that PJM would likely be willing to approve exceptions if needed to facilitate continuous SCR operation during overnight off-peak periods. See Key-Con comments, attachment 3 at 20-22. Moreover, the operating data reported for Keystone to EPA for May and June of 2022 appear to show that Key-Con has in fact received approval of such an exception, because the Keystone units' ratios of daytime maximum load levels to overnight minimum load levels for much of this period fall below the ratio's default floor value that would apply to the units in the absence of an exception.
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52. The commenters generally chose not to discuss their opportunities to influence PJM's dispatch instructions. However, the comments do include some implicit recognition that those opportunities exist, most of which consist of qualifiers such as "in general," "not wholly," or "in large part" to various statements. The clearest confirmation that those opportunities exist is found in a statement by Key-Con that the proposed emission rates "will require Key-Con to forfeit most dispatch opportunities at lower electrical loads as directed by PJM and suffer resultant revenue impacts in order to maintain compliance with the limits." EPA views this statement as an implicit admission that Key-Con has the ability to "forfeit . . . dispatch opportunities" when it believes such forfeiture is in its interest. Given PJM's undisputed role in directing units' dispatch, the only mechanism for a source to accomplish such a "forfeiture" would be for the source to provide information to PJM that causes PJM to issue dispatch instructions that do not require the units to dispatch at low load levels.
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53. For the complete hourly data discussed in this paragraph, see PA SCR unit 2021-2022 hourly ozone season data.xlsx, available in the docket for this action. The spreadsheet contains graphs for each unit illustrating the changes in load levels and SCR operation described here. EPA notes that the 2022 data have not been used to set the emission limits being finalized in this rule but are being presented to support EPA's response to the sources' comments relating to PJM's control of dispatch decisions.
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54. CAA section 184(a) establishes a commission for the OTR, the OTC, consisting of the Governor of each state or their designees, the Administrator or their designee, the Regional Administrators for the EPA regional offices affected (or the Administrator's designees), and an air pollution control official representing each state in the region, appointed by the Governor. Section 184(c) specifies a procedure for the OTC to develop recommendations for additional control measures to be applied within all or a part of the OTR if the OTC determines that such measures are necessary to bring any area in the OTR into attainment for ozone by the applicable attainment deadlines. On June 8, 2020, the OTC submitted a recommendation to EPA for additional control measures at certain coal-fired EGUs in Pennsylvania. See 85 FR 41972 (/citation/85-FR-41972); July 13, 2020.
55. Conemaugh and Keystone submitted data in response to the OTC's CAA section 184(c) recommendation identifying the MW input at which it typically operates or can operate the SCRs. EPA reviewed the historic operating data for these facilities as it did for Homer City, Montour, and Cheswick, and found that Keystone and Conemaugh's stated thresholds were consistent with the data. EPA thus relied upon the stated values for Keystone and Conemaugh in the development of this action's proposed rates.
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56. See Appendix 2 of the TSD for the proposal to compare the proposed weights and rates to the final values in Table 6 of this preamble.
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57. 44 U.S.C. 3501 (https://www.govinfo.gov/link/uscode/44/3501) et seq.
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58. 5 CFR 1320.3(c) (https://www.ecfr.gov/current/title-5/section-1320.3#p-1320.3(c)) (emphasis added).
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59. 65 FR 67249 (/citation/65-FR-67249), 67250 (/citation/65-FR-67250) (November 9, 2000).
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60. Executive Order 12898 (/executive-order/12898) can be found 59 FR 7629 (/citation/59-FR-7629) (February 16, 1994).
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61. The RIA for that separate EPA action can be found at www.regulations.gov (http://www.regulations.gov) under the docket number EPA-HQ-OAR-2021-0668. Section 7.4 begins on page 7-9.
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62. See www.regulations.gov (http://www.regulations.gov), Docket EPA-R03-OAR-2017-0615-0059, pp. 14 -17.
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[FR Doc. 2022-18669 (/d/2022-18669) Filed 8-30-22; 8:45 am]

BILLING CODE 6560-50-P

June 3, 2024
Kyle Ferrar, MPH
Western Program Director
FracTracker Alliance

Re: Expert Witness Comments on Scope of U.S. EPA State Implementation Plan of RACT Requirements for Oil and Gas Sites in California

To whom it may concern,

I am the Western Program Director of the 501(c)3 FracTracker Alliance, an academic research organization focused on issues of data transparency and environmental health risks associated with fossil fuel extraction. I have been working on fossil fuel extraction issues for over 17 years, beginning with coal-fire energy generation and Marcellus Shale gas extraction issues in Pennsylvania, working as a research specialist at the Center for Healthy Environments and Communities at the University of Pittsburgh Graduate School of Public Health. I have focused on California oil and gas extraction since 2012, and was a contributing author to the California Council on Science and Technology State Bill 4 reports on oil and gas well stimulation, in addition to publishing articles on multiple aspects of oil and gas extraction and well stimulation on my own[1]. You can find my curriculum vitae at the end of this document (Appendix A).

As an environmental health professional specializing in exposure assessment and the fate and transport of pollutants through environment media, I would like to state that strict leak detection and reporting (LDAR) standards provide the initial and most important layer of public health protections for communities living near oil and gas extraction operations. Increases in the regularity of inspections as well as the level of scrutiny result in compounding decreases of future discoveries of uncontrolled emissions[2]. As a certified thermographer, I have witnessed such results first hand. It is therefore vital to prioritize LDAR inspections and require established EPA methods of evaluation, specifically Method 21, for all oil and gas wells, including California's heavy oil wells. When low producing wells or wells producing heavy oil are exempt from LDAR requirements, small leaks can grow unchecked. Understanding what proportion of oil and gas wells produce heavy oil, and the proportion of production that heavy oil constitutes is therefore incredibly important.

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[1] CCST. 2016. An Independent Assessment of Well Stimulation in California, Vol 3(SB4). https://ccst.us/reports/an-independent-scientific-assessment-of-well-stimulation-in-california-volume-3/
[2] Lucy C. Cheadle, Travis Tran, James F. Nyarady, Carolyn Lozo, 2020. Leak detection and repair data from California's oil and gas methane regulation show decrease in leaks over two years. Environmental Challenges. Volume 8. 100563 ISSN 2667-0100. https://doi.org/10.1016/j.envc.2022.100563.

Both regularity and thoroughness of inspections are top priorities to identify leaking equipment and to keep uncontrolled emissions to a minimum. LDAR inspections should occur at minimum at monthly intervals for all oil and gas infrastructure, as recommended in the state control technique guidelines[3]. The implementation of OGI cameras should be applied as any other methane detection instrument utilized under Method 21 guidelines. Every piece of equipment should be thoroughly inspected. Additionally, all equipment employed to conduct Method 21 inspections should be able to detect methane at low concentrations. Current standards require methane detection equipment with a minimum detection limit of 1,000ppm, which is unreasonably high. Equipment used for Method 21 should have a minimum detection limit near that of optical gas imaging technology, where a typical handheld camera can accurately detect emissions at concentrations of down to 20 ppm[4]. Even an off-the shelf Klein methane detector costing just $100 at Home Depot has a detection limit near 50 ppm[5].

Summary of California Heavy Crude Oil Operations

At least a third of California's oil and gas infrastructure is exempt from LDAR requirement, while the percentage of wells is much higher. According to the California Air Resources Board and literature on LDAR effectiveness, 34% of California oil and gas components are exempt due to handling oil with API (American Petroleum Institute) gravity less than 20°[6]. These figures are based on data from the last statewide survey, in 2007. Utilizing available regulatory data from the California Department of Geological Energy Management, I have summarized the proportion of unplugged oil and gas wells that currently comprise a portion of this category.

Monthly summaries of wellsite production and injection volumes were downloaded from CalGEM for the years 2014-2023[7][8]. Data was cleaned and summarized using Python v3.9.12. The python code has been uploaded to FracTracker data repository for public access[9]. A database was created to generate average API gravity values and assign the values to unique production formation pool codes, in order to assess the counts of injection wells also involved in the production of heavy oil.

The data shows that the percentage of heavy oil making up California's total overall production is increasing over time, as California's more easily accessible midweight and light crude are

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[3] State of California Air Resources Board. 2018. Staff Report: Proposed Submission of Claifornia's GHG Standards for Crude Oil and Natural Gas Facilities into the California State Implementation Plan. ttps://ww2.arb.ca.gov/sites/default/files/2020-04/O_G%20CTG%20-%20Staff%20Report.pdf

[4] Teledyne Flir. July 1, 2022. Understanding Cooled Vs Uncooled Optical Gas Imaging. https://www.flir.com/discover/instruments/gas-detection/understanding-cooled-vs-uncooled-optical-gas-imaging/

[5]https://www.homedepot.com/p/reviews/Klein-Tools-Combustible-Gas-Leak-Detector-ET120/303184519/5

[6] Lucy C. Cheadle, Travis Tran, James F. Nyarady, Carolyn Lozo, 2020. Leak detection and repair data from California's oil and gas methane regulation show decrease in leaks over two years. Environmental Challenges. Volume 8. 100563 ISSN 2667-0100. https://doi.org/10.1016/j.envc.2022.100563.

[7] https://wellstar-public.conservation.ca.gov/General/PublicDownloads/Index

[8] https://filerequest.conservation.ca.gov/?q=production_injection_data

[9] https://fractracker.box.com/s/jv1t0n6zfofpnbrulmzodieo94xlb9ny

exhausted. The data also shows that shorter term variances are additionally influenced by factors extraneous to the downhole composition of crude oil, such as economic turndowns and regulatory pressures. **On average, about 74% of California crude is considered heavy, based on data from 2021-2023. An average of the last ten years shows that about 72% of the crude oil produced in California had a gravity of less than 20°.**

Based on average API gravity values for the years 2014-2023, the results of my analysis show that 79,785 (82.7%) of currently unplugged oil and gas production *and injection wells* are either producing from reservoir pools with heavy oil (API<20°), or injecting into or monitoring formations that produce heavy oil.

The numbers are similar if the dataset is limited to only the production wells, as injection wells are likely to have their own LDAR requirements associated with Class II RCRA rules. **Of the 65,019 unplugged oil and gas *production* wells (well status = OG) in the state, with attributable gravity values, 51,743 (79.6%) reported production of oil with an average API gravity value of less than 20°, based on the ten-year average of oil gravity values.**

Of the 65,019 unplugged OG wells, 59,772 (91.9%) were idle or produced less than an average of 15 barrels per day.

As the current proposal for the SIP rules specifically exempt idle wells, the proportion of idle wells in the state was also calculated. It is also important to monitor idle wells using LDAR methods due to the high percentage of idle wells that have been documented to be leaking in California[10]. Idle wells currently make up 39.1% (39,872) of unplugged wells in California.

Optical Gas Imaging

While working in partnership with the Earthworks Community Empowerment Project, I personally inspected hundreds of urban and community oil and gas drilling sites in California from 2016 through 2022. I filed numerous complaints with regional air districts, which resulted in many dozens of enforcement actions including notices of violations. One major result of the work was the discovery of the leaking heavy oil wells operated by Sunray Petroleum, Inc in the HoodBloemer lease in the Morningstar neighborhood of Bakersfield in the spring of 2022.

Following the discovery of the leaking wells operated by Sunray Petroleum, Inc in the HoodBloemer lease, CalGEM ordered inspections of other idle wells in the region. The agency immediately discovered an additional 49 leaking wells[11]. These wells are listed in Table 1, below. Average API gravity of oil production values have been added to the table. All 49 of the wells

[10] Eric D. Lebel, Harmony S. Lu, Lisa Vielstädte, Mary Kang, Peter Banner, Marc L. Fischer, and Robert B. Jackson. 2020. Environmental Science & Technology 2020 54 (22), 14617-14626. DOI: 10.1021/acs.est.0c05279

[11] California Department of Geological Energy Management. List of Leaking Wells in Bakersfield. From CalGEM website. https://www.conservation.ca.gov/well-inspections-repair-updates

reported average API values of under 20°, and have therefore avoided detection. This is often the issue, as much of the deteriorating oil and gas infrastructure that degrades to the point of leaking in California is considered heavy oil operations.

This particular case of dozens of documented leaking idle and low producing wells is also a prime example of why “wellhead-only” sites should not be exempt from LDAR requirements. All of the oil wells identified as leaking near the Morningstar neighborhoods were “wellhead-only” wellsites, where all of the infrastructure had been removed except for the wellhead. Several weeks following the initial complaint filed with the San Joaquin Valley Air Pollution Control District (SJVAPCD), I returned to conduct follow-up inspections on the leaking wells. My notes from that field trip titled “Oil and Gas Optical Gas Imaging Notes 6/8/22 - 6/9/22” is included as Appendix B at the end of this report. Pictures of the leaking wellheads are presented in that report, and the pictures indicate where the leaks on the wellheads had occurred.

Several months after the discovery of the leaking Sunray Petroleum, Inc, I spent several days in the field assessing the work that had been completed by CalGEM contractors and operators to service the massive inventory of idle and low producing heavy oil wells that had been long disregarded in California. I inspected dozens of well sites, documenting many cases where old equipment had been replaced, bolts tightened, or thread sealant applied to connections. While many of the leaks had been mitigated, I documented nearly 70 leaks and submitted complaints to the local air districts. The list of leaking wellsites identified are listed below in Table 2. The data shows that 34 wellsites had documented leaks, the majority (18) were leaking directly from the wellhead. Of the 34 wellsites, 23 (68%) were heavy oil wells. The table includes the complaint identification numbers and links to the OGI footage.

Conclusions

The vast majority of oil and gas extraction operations in California produce heavy crude oil. Exempting equipment servicing heavy crude oil operations would eliminate a substantial portion of California’s oil and gas infrastructure from leak detection and reporting requirements, including the vast majority of oil wells producing the vast majority of crude oil. The result would be a considerable lack of emissions reductions that would otherwise occur. Many of these potential ongoing leaks are documented below in the table of OGI field work completed by myself, as well as the leaks documented by CalGEM. The many heavy oil facilities where I filmed and documented uncontrolled methane and VOC emissions were not likely to otherwise have been inspected. There is no telling how long these wells were leaking. Without scrutiny from the public, the ongoing leaks would have continued to put communities at elevated risk of health impacts related to local air quality degradation from toxic and carcinogenic volatile organic compounds, elevated regional ozone pollution, and the global impacts of climate change.

Tables

Table 1. CalGEM dataset of leaking wells discovered in June 2022 near Bakersfield. These wells were identified by CalGEM as leaking, following the discovery of the leaking Sunray Petroleum, LLC wells in the Morningstar neighborhood.

API	Well Designation	Operator	Well Issue	Repair Status	lat	lon	Oil API Gravity
402908759	Needham-Bloemer1	Citadel Exploration Inc.	Leaking methane	Repaired	35.4132	-118.913	0
402908763	Needham-Bloemer14	Citadel Exploration Inc.	Leaking methane	Repaired	35.4144	-118.912	0
402908770	Needham-Bloemer25	Citadel Exploration Inc.	Leaking methane	Repaired	35.4156	-118.913	0
402908775	Needham-Bloemer30	Citadel Exploration Inc.	Leaking methane	Repaired	35.4164	-118.908	0
402908776	Needham-Bloemer31	Citadel Exploration Inc.	Thought to be Leaking methane (6/2/2022)	Multiple subsequent in-person inspections found no leak	35.4138	-118.913	0
402908779	Needham-Bloemer35	Citadel Exploration Inc.	Leaking methane	Repaired	35.4150	-118.91	1.875
402957338	Needham-Bloemer38	Citadel Exploration Inc.	Leaking methane	Repaired	35.4138	-118.91	0

402908761	Needham-Bloemer4	Citadel Exploration Inc.	Leaking methane	Repaired	35.4132	-118.909	0
403062148	Needham-Bloemer Shakedown St#2	Citadel Exploration Inc.	Leaking methane	Repaired	35.4140	-118.909	2.5
402908771	Needham-Bloemer26	Citadel Exploration Inc.	Thought to be Leaking methane (6/2/2022)	Multiple subsequent in-person inspections found no leak	35.4156	-118.912	1.875
402908772	Needham-Bloemer27	Citadel Exploration Inc.	Leaking methane	Repaired	35.4156	-118.91	1.875
402908773	Needham-Bloemer28	Citadel Exploration Inc.	Thought to be Leaking methane(6/2/2022)	Multiple subsequent in-person inspections found no leak	35.4156	-118.909	3.75
402988951	Needham-Bloemer72	Citadel Exploration Inc.	Leaking methane	Repaired	35.4159	-118.91	0
403063440	Needham-Bloemer Thunderstruck #4	Citadel Exploration Inc.	Thought to be Leaking methane(6/2/2022)	Multiple subsequent in-person inspections found no leak	35.4138	-118.906	0

402908789	Bloemer10	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.4011	-118.905	0
402969434	Bloemer120	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.4011	-118.904	0
402908792	Hood-Bloemer1 A	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.4029	-118.905	0
402971724	Hood-Bloemer108D	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.4028	-118.905	0
402908794	Hood-Bloemer3 A	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.4021	-118.904	0
402969433	Hood-Bloemer109	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.4024	-118.904	0
402908871	Afana1	Zynergy, LLC	Leaking methane	Repaired	35.4058	-118.911	0
402951205	Afana12	Zynergy, LLC	Leaking methane	Repaired	35.4074	-118.911	0
402908872	Afana2	Zynergy, LLC	Leaking methane	Repaired	35.4071	-118.913	0
402908873	Afana3	Zynergy, LLC	Leaking methane	Repaired	35.4058	-118.91	0
402973711	Afana5V	Zynergy, LLC	Leaking methane	Repaired	35.4063	-118.909	0
402908879	Afana9	Zynergy, LLC	Leaking methane	Repaired	35.4087	-118.914	0
402908877	Afana7	Zynergy, LLC	Leaking methane	Repaired	35.4086	-118.914	0

402906740	K.C.L. B52	Griffin Resources	Leaking methane	Repaired	35.3665	-119.064	15.42
402908238	K.C.L. A53	Griffin Resources	Leaking methane	Repaired	35.3638	-119.064	15.42
402908241	K.C.L. A84	Griffin Resources	Leaking methane	Repaired	35.3623	-119.058	15.42
402908242	K.C.L. B61	Griffin Resources	Leaking methane	Repaired initially; evidence of low level leak; repair work to continue	35.3677	-119.062	15.42
402908257	K.C.L. D87	Griffin Resources	Leaking methane	Repaired	35.3575	-119.057	15.42
402900741	K.C.L. D77	Griffin Resources	Leaking methane	Repaired	35.3569	-119.06	15.42
402908243	K.C.L. B62	Griffin Resources	Leaking methane	Repaired	35.3658	-119.062	15.42
402908246	K.C.L. B73	Griffin Resources	Leaking methane	Repaired	35.3641	-119.06	15.42
402908251	K.C.L. D67	Griffin Resources	Leaking methane	Repaired	35.3569	-119.062	15.42
402908252	K.C.L. D75	Griffin Resources	Leaking methane	Repaired	35.3605	-119.06	15.42
402908258	K.C.L. D88X	Griffin Resources	Leaking methane	Repaired	35.3564	-119.057	15.42
402908245	K.C.L. B72	Griffin Resources	Leaking methane	Repaired	35.3659	-119.06	15.42

402908239	K.C.L. A64	Griffin Resources	Leaking methane	Repaired	35.3623	-119.062	15.42
402908259	K.C.L. A78-4	Griffin Resources	Leaking methane	Repaired	35.3615	-119.059	15.42
402906770	10	E&B Natural Resources	High Pressure	Repaired	35.3651	-119.055	0
402906772	12	E&B Natural Resources	High Pressure	Repaired	35.3600	-119.055	0
402906773	14	E&B Natural Resources	High Pressure	Repaired	35.3594	-119.056	0
402906762	2	E&B Natural Resources	High Pressure	Repaired	35.3695	-119.055	0
402906763	3	E&B Natural Resources	High Pressure	Repaired	35.3641	-119.056	0
402906765	5	E&B Natural Resources	High Pressure	Repaired	35.3659	-119.056	0
402906766	6	E&B Natural Resources	High Pressure	Repaired	35.3605	-119.056	0
402906769	9	E&B Natural Resources	High Pressure	Repaired	35.3650	-119.056	0

Table 2. List of leaking heavy oil wells identified by the Western Program Director of FracTracker Alliance in August 2022. These cases of uncontrolled emissions were reported to the local air districts as complaints, and action was taken by the air districts to ensure the leaks were mitigated.

Date	District	Complaint ID	API	Field	Well Operator	lat	lon	API Gravity	Link to OGI
8/1/2022	SCAQMD	345609	403716431	Santa Fe Springs	WG Holdings SPV, LLC	33.94	-118.08	0.0	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/1/2022	SCAQMD	345610	403722606	Wilmington	Pacific Coast Energy Company LP	33.85	-118.22	9.0	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/1/2022	SCAQMD	345606	403700809	Bandini Field	Four Teams Oil	34.00	-118.16	21.7	https://app.box.com/s/hl0sy01t50w9egxxaj6ilxt6qgk59rs6
8/2/2022	SCAQMD	345628	403709238	Long Beach	W. W. Beldin	33.82	-118.19	0.0	https://app.box.com/s/9y7noyetsyw471qvygyh6j6oa2hogu5f
8/2/2022	SCAQMD	345631	403725235	Long Beach Field	Featherstone & Preston Inc.	33.82	-118.19	0.0	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/2/2022	SCAQMD	345633	403710437	Long Beach Field	Signal Hill Petroleum, I.C. lease	33.82	-118.18	8.7	https://app.box.com/s/c3919qgqmiexlcvego0sv5sxnslzp739
8/2/2022	SCAQMD	345626	403712080	Long Beach	The Termo Company	33.82	-118.19	22.5	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/3/2022	SCAQMD	345640	37072446	El Segundo		33.92	-118.41	0.0	https://app.box.com/s/xfbcxepeg6vr60wcgsmwq1xq9tuflngb
8/3/2022	SCAQMD	345660	403711318	Long Beach	Signal Hill Petroleum	33.81	-118.18	0.0	https://app.box.com/s/gcoq9n6hye3a27qiok7yxbunjd2n1i83
8/3/2022	SCAQMD	345643	403716946	Torrance	E&B Natural Resources	33.80	-118.29	3.3	https://app.box.com/s/rkqm7lmr0v2bb11e0ymc7qb92q7af64t
8/3/2022	SCAQMD	345642	403717088	Torrance	Hunt Enterprises	33.80	-118.30	8.2	https://app.box.com/s/37jyqc7w5l0tbl3ro4v3mpry1qok5k1c
8/3/2022	SCAQMD	345648	403717754	Torrance	Brea Canon Oil Company	33.80	-118.29	17.3	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/3/2022	SCAQMD	345641	403717335	Torrance	Signal Hill Petroleum	33.81	-118.31	59.9	https://app.box.com/s/vea600vs58h57dr3hsksvaszptiwquze

8/3/2022	SCAQMD	345653	403709946	Long Beach	Signal Hill Petroleum	33.81	-118.19	156.6	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/4/2022	SCAQMD	345676	403712074	Montebello	Signal Hill Petroleum	33.80	-118.17	0.0	https://app.box.com/s/ilso4owif7c8grffiwwj3yugkawg6dwz
8/4/2022	SCAQMD	345671	403710761	Long Beach	Signal Hill Petroleum	33.80	-118.17	8.3	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/4/2022	SCAQMD	345665	403710264	Long Beach	Signal Hill Petroleum	33.81	-118.18	8.8	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/4/2022	SCAQMD	345673	403711510	Long Beach	Signal Hill Petroleum	33.80	-118.17	11.0	https://app.box.com/s/dfd2gzab9f13x2ltsz5j3wnwfja4oty8
8/4/2022	SCAQMD	345661	403708399	Long Beach	C. E. Allen Co., Inc.	33.81	-118.18	24.8	https://app.box.com/s/b6fsse6yhq7f857shwlzk0s8w96mu1z7
8/4/2022	SCAQMD	345664	403706377	Long Beach	Signal Hill Petroleum	33.80	-118.18	85.1	https://app.box.com/s/3p494x8j465re7c06vyw5xny8qi34zd7
8/4/2022	SCAQMD	345672	403711846	Long Beach	Signal Hill Petroleum	33.80	-118.17	89.1	https://app.box.com/s/xcy9gbqxtl13jw42mq3td6a9jb56k1lx
8/4/2022	SCAQMD	345667	403711812	Long Beach	Signal Hill Petroleum	33.81	-118.18	96.8	https://app.box.com/s/6qvun24dpvpj1rdadfhj5ppru19uhiux
8/5/2022	VCAPCD	2022-064	411103705	South Mountain	CalNRG Operating, LLC	34.34	-119.05	6.5	https://app.box.com/s/a294x0jh170vjnwohsbbeb897thoouzv
8/5/2022	VCAPCD	2022-064	411104368	Aera Ventura	Aera	34.32	-119.29	60.0	https://app.box.com/s/csb9hpflbcq0bib8keu4kp40nbdi42rb
8/6/2022	SJVAPCD	S-2208-035	402920642	Ten Section	San Joaquin Facilities Managament	35.29	-119.22	0.0	https://app.box.com/s/fjh4gddgpsn5iifacc3zl2nvgoeskapv
8/6/2022	SJVAPCD	S-2208-040	402938421	Midway Sunset	MS Investors, LLC	35.08	-119.40	3.2	https://app.box.com/s/bgojgibu89rzxb0kuf5g4brutq1cdns2
8/6/2022	SJVAPCD	S-2208-035	402900275	Ten Section	San Joaquin Facilities Managament	35.29	-119.22	6.3	https://app.box.com/s/z693a95ufowb8b2q7ureo918by81eilz
8/6/2022	SJVAPCD	S-2208-030	402948052	Midway Sunset	25 Hill Properties	35.13	-119.45	9.2	https://app.box.com/s/kh3e0s1dvnb3rkj2m255yxgneutukrbr
8/6/2022	SJVAPCD	S-2208-021	402914358	Mountain View	The Termo Company	35.18	-118.84	18.2	https://app.box.com/s/q7wsljptujr5p8377zg9r4s3s0j8c3tm

8/6/2022	SJVAPCD	S-2208-022	402914431	Mountain View	Sequoia Exploration, Inc.	35.21	-118.84	20.7	https://app.box.com/s/q86vzlx1u8uv74aip3oa5lmqmsy9le5a
8/6/2022	SJVAPCD	S-2208-022	402946808	Mountain View	Sequoia Exploration, Inc.	35.21	-118.84	22.1	https://app.box.com/s/r0x1kkgpoxniq5fe03jjl3tneb91ouer
8/7/2022	SJVAPCD	S-2208-023	402908187	Fruitvale	Sunray Petroleum	35.38	-119.06	0.0	https://app.box.com/s/2n1ji9oxtdpb4y66gdj9lx42azyzukdo
8/7/2022	SJVAPCD	S-2208-023	402908185	Fruitvale	Sunray Petroleum	35.38	-119.06	0.0	https://app.box.com/s/qzfjyh8c3vrpbhr0z8ebtobze8c66bfs
8/7/2022	SJVAPCD	S-2208-034	402962091	Edison	Redbank Oil Company	35.34	-118.91	0.0	https://app.box.com/s/natgldd7shrbj13p7qtue0cw6my1xq9u

Appendix A: Curriculum Vitae

Education

Doctor of Public Health (DrPH), May 2010 - July 2012, Unfinished
University of Pittsburgh
Graduate School of Public Health
Department of Environmental and Occupational Health (EOH)

Master of Public Health (MPH), May 2008 - May 2010
University of Pittsburgh
Graduate School of Public Health
Department of Environmental and Occupational Health (EOH)
Certificate: Public Health Preparedness and Disaster Response
Certificate: Environmental Health Risk Assessment
Certificate: LGBT Health Studies

Bachelor of Science (BS), September 2004 - May 2008
University of Pittsburgh
Department of Biological Sciences
Major: Biological Sciences
Minor: Chemistry

Experience

<u>Environmental Health, Staff Researcher July 2007 – 2013</u>
Center for Healthy Environments & Communities (CHEC)

Projects Managed

The Allegheny River Stewardship Project

- Collected fish, water, and sediment samples during multiple site assessments
- Managed student workers and volunteers during site assessments and community engagement

Autism and Heavy Metal Exposures, Modeling Coal-Fired Power Plant Plumes

- Developed computer models of emissions

Geo-positioning and Evaluation of Coal Fired Power Plant Locations, Coal Combustion Waste Sites and Beneficial Use Sites

- Compiled databases of coal waste sites and power stations
- Correlated sites of interest with indicators of environmental injustice

Implementation of the ‘www.Fractracker.org’ web platform

- Conducted trainings with community partners

Contaminant Concentrations in Fish Tissues using atomic fluorescence spectrometry

- Analyzed fish tissue samples using atomic fluorescence

Identification of Health Impacts and Symptoms Attributed to Unconventional Natural Gas Drilling

- Engaged community members, documented and cataloged their experiences

Assessment of Marcellus Shale Wastewater Treatment Facilities

- Evaluated the impact of regulatory requests on wastewater quality

Teaching Assistant September 2010 - 2013

University of Pittsburgh, Graduate School of Public Health

- Developed course material for two graduate level MPH courses
- Managed student grades

Graduate Student Assistant April 2010 - 2013

Allegheny County Health Department (ACHD) Air Toxics Committee

- Reviewed potential health endpoints
- Presented data on the current state of air quality research
- Dictated meeting discussions of technical issues
- Drafted language for the guidelines

Environmental Consultant Jan. 2009 – Summer 2011

University of Pittsburgh Environmental Law Clinic

- Advised on environmental and policy issues for live clinical cases as an acting expert witness
- Conducted reviews of regulatory files

Western Program Director, FracTracker Alliance July 2013 - Present

List of Relevant Publications

CCST Publication, Contributing Author Seth B. C. Shonkoff, Preston Jordan, Adam Brandt, Kyle Ferrar, Randy Maddalena, Ben K. Greenfield, Michael Jerrett, Matthew Heberger, Thomas E. McKone (2015). Volume II Chapter 4; Public Health Risks Associated with Current Oil and Gas Development in The Los Angeles Basin.
(http://ccst.us/projects/hydraulic_fracturing_public/SB4.php).

CCST Publication, Contributing Author Preston Jordan, Adam Brandt, Kyle Ferrar, Laura Feinstein, and Scott Phillips (2015). Volume II Chapter 5; A Case Study of the Potential Risks Associated with Hydraulic Fracturing in Existing Oil Fields in the San Joaquin Basin
(http://ccst.us/projects/hydraulic_fracturing_public/SB4.php).

Journal Article, Primary Author Kyle J. Ferrar, Drew R. Michanowicz, Charles L. Christen, Ned Mulcahy, Samantha L. Malone, and Ravi K. Sharma (2013). Assessment of Effluent Contaminants from Three Facilities Discharging Marcellus Shale Wastewater to Surface Waters in Pennsylvania. Environmental Science and Technology. 47 (7), 3472-3481
DOI:10.1021/es301411q (http://pubs.acs.org/doi/abs/10.1021/es301411q)

Journal Article, Primary Author Kyle J Ferrar, Jill Kriesky, Charles L Christen, Lynne P Marshall, Samantha L Malone, Ravi K Sharma, Drew R Michanowicz, and Bernard D Goldstein (2013). Assessment and longitudinal analysis of health impacts and stressors perceived to result from unconventional shale gas development in the Marcellus Shale region. International Journal Of Occupational And Environmental Health Vol. 19 , Iss. 2,2013
White Paper, Contributing Author Michanowicz D, Malone S, Ferrar K, Kelso M, Christen C, Volz CD, Goldstein B. (2011). Pittsburgh Regional Environmental Threats Analysis (PRETA) Report - PRETA Air: Ozone. Center for Healthy Environments & Communities, Department of Environmental & Occupational Health, University of Pittsburgh Graduate School of Public Health.
(http://www.chec.pitt.edu/documents/PRETA/CHEC%20PRETA%20Ozone%20Report.pdf)

White Paper, Contributing Author CD Volz, K Ferrar, D Michanowicz. 2011. Contaminant Characterization of Effluent from Pennsylvania Brine Treatment Inc., Josephine Facility Being Released into Blacklick Creek, Indiana County, Pennsylvania.
(http://www.epa.gov/ordntrnt/ORD/hfstudy/epa600r11047.pdf#page=23)

Conference Abstract, Contributing Author Bain, DJ; Michanowicz, AR; Ferrar, KJ. 2010. Hydraulic Fracturing Return Waters and Legacy Landscapes. American Geophysical Union, Fall Meeting 2010, abstract #H21B-1028 (http://adsabs.harvard.edu//abs/2010AGUFM.H21B1028B)

Appendix B: Field Notes

Oil and Gas Optical Gas Imaging Notes 6/8/22-6/9/22

Bakersfield

FracTracker Alliance spent two days using a FLIR GF320 optical gas imaging (OGI) camera to inspect oil and gas operations in and near Bakersfield. The target of this short field trip was to focus on idle wells that may be leaking from wellbores, casing hanger flanges, and other wellhead infrastructure. The trip was conducted as a follow-up to the recent discovery of leaking idle wells in a residential section of the Kern Bluff oil field in the east Bakersfield town of Morning Star on a previous field trip.

Morning Star

All of the Sunray Petroleum and Zynergy Energy wells in the Hood-Bloemer and Afana leases were thoroughly inspected for leaks, including the HoodBloemer lease well previously identified and reported to the air district by FracTracker Alliance. While leaks had been identified at these wellsites during the previous inspection, no leaks were found during the follow-up. It was clear that remedial work had been completed at the majority of the wellsites. The images below show where leaks had previously been detected on the wellheads, and where the leaks had been sealed. New stainless steel end caps on piping, new bolts on casing hanger flanges, new teflon tape on connectors, and new pressure gauges had been installed on most, but not all, wells. The pressure gauges were the most noticeable and are used to monitor the pressures at the wellhead. This will allow operators and regulators to monitor for issues that could lead to blowouts and future leaks. Examples of these devices are shown in the pictures below.

There were of course still some issues identified in these fields. For example, below is a picture of an open well bore with the cap disconnected. Emissions were not detected at this well.

Bakersfield Financial District

This field trip inspected for emissions from idle wells in several other neighborhoods of Bakersfield, at wells operated by Sunray Petroleum as well as a handful of other operators. Most sites were found to be leak free. Uncontrolled emissions were detected at three wells in the Financial District, all operated by Griffin Resources. The wells were identified as B61, B52, and A64. An example of the emissions from well A64 is shown in the image below. While this site and the other leaking sites in downtown had indications of operators replacing valves and adding pressure gauges, there were still leaks detected. The leak at this site is coming from the valve to the right of the Kelly bushing identified in the picture below. The following pictures show where the plume is located in the OGI footage. The leak is difficult to see with an untrained eye, and further obfuscated by the chainlink fence.

While at this site I had a chance encounter, crossing paths with another thermographer working for the California Department of Conservation. He informed me that operators had been ordered to do work at multiple sites, and the DOC was conducting follow-up inspections on many of the wellsites in the area.

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FracTracker Finds Widespread Hydrocarbon Emissions from Active & Idle Oil and Gas Wells and Infrastructure in California

fractracker.org/2022/08/fractracker-finds-widespread-hydrocarbon-emissions-from-active-idle-oil-and-gas-wells-and-infrastructure-in-california/

August 22, 2022

By Kyle Ferrar, MPH/August 22, 2022 / 15 minute read

1 Comment on FracTracker Finds Widespread Hydrocarbon Emissions from Active & Idle Oil and Gas Wells and Infrastructure in California

VIEW STORY MAP: TOXIC EMISSIONS FILMED AT LEAKING OIL AND GAS INFRASTRUCTURE IN CALIFORNIA

VIEW DYNAMIC MAP: FRACTRACKER OIL AND GAS LEAKING INFRASTRUCTURE COMPLAINTS

Overview

Using a FLIR-Teledyne GF320 optical gas imaging camera, FracTracker spent seven days (August 1-7, 2022) inspecting oil and gas infrastructure in Los Angeles County, Kern County, and Ventura County. The inspections of drilling sites and production facilities prioritized idle well-sites, following the discovery of 49 leaking idle wells in Bakersfield. In addition to idle wells, the field trip focused on neighborhood and urban drilling sites, which present the highest risk of exposure to volatile organic compounds (VOCs) for frontline communities. VOCs are known to cause respiratory harm and certain chemicals such as benzene are known carcinogens. Benzene and other toxic VOCs are components of gaseous emissions from oil and gas production infrastructure, and concentrations of these chemicals have been found to be elevated near oil and gas production facilities.

FracTracker inspected over 400 wells and other pieces of infrastructure at nearly 100 different drill sites. Leaks and sources of uncontrolled emissions were documented in each of the three counties. In total, FracTracker filed 68 air quality complaints with local air districts: 41 to the South Coast Air Quality Management District, 23 to the San Joaquin Valley air pollution control district, and four to the Ventura County air pollution control district. Inspectors from each district are actively investigating and several notices of violations have already been issued.

The complaints included leaks and uncontrolled emissions documented from the following pieces of oil production infrastructure:

- 23 well-heads, including 21 idle wells
- 35 tank facilities
- 9 VOC combustors
- 2 flares

The full FracTracker report includes discussions of these various sources of leaks and uncontrolled emissions, as well as the applicable state and local regulations. A digital map of the 68 complaints with links to OGI and DSLR imagery of the facilities and emissions plumes is provided, as well as a guided story map presenting descriptive summaries of particularly serious leaks and other complaints generally representative of common leaks. These widespread leaks highlight the need for a statewide setback between existing oil and gas projects and homes, schools, and other sensitive receptors in order to reduce exposures for frontline communities. Governor Newsom has signaled support for this type of protection through legislation and regulations–the state should adopt and implement these long overdue protections as quickly as possible.

Toxic Emissions Filmed at Leaking Oil and Gas Infrastructure in California

This StoryMap explores a selection of wells and production facilities where emissions were documented. The map takes viewers on a tour of these production facilities and presents the OGI footage of the leaks and plumes of emissions.

Place your cursor over the image and scroll down to advance the StoryMap.

Click on the icon in the bottom left to view the legend.

Scroll to the end of the StoryMap to learn more and access the data sources.
View Full Size Map | Updated 8/21/2022 | Map Tutorial

Introduction

FracTracker Alliance recently took to the field in collaboration with grassroots groups and community organizations in California including the Central California Environmental Justice Network (CCEJN) in Kern County, Climate First: Replacing Oil and Gas (CFROG) in Ventura County, and Sierra Club in Los Angeles County. From August 1-7, 2022, FracTracker's Western Program Coordinator (a certified thermographer) inspected over 400 individual oil and gas wells and pieces of infrastructure at nearly 100 different drill sites, in the counties of Los Angeles, Kern, and Ventura. Using state-of-the-art technology called optical gas imaging (OGI), we documented otherwise invisible toxic pollutants and greenhouse gas emissions (GHGs) being released from oil and gas wells and other infrastructure. These emissions represent an immediate environmental health threat to frontline communities and all individuals present near these oil production facilities.

Using a FLIR GF320 optical gas imaging camera, FracTracker visually observed and recorded leaks and uncontrolled releases of methane and volatile organic compound (VOC) emissions. These toxic, carcinogenic pollutants and greenhouse gasses are invisible to the naked eye, but visible in the infrared spectrum. This short report details the findings of this field work and presents the footage of leaks and uncontrolled emissions discovered at the oil production well-sites and collection facilities. All leaks and emission sources have been reported as complaints to the local air districts as well as other appropriate agencies responsible for emergency response. The locations of these leaks and uncontrolled emissions can be viewed in the map in Figure 1 below.

FracTracker Oil and Gas Leaking Infrastructure Complaints

This interactive map looks at oil and gas drilling and production sites in California counties where leaks were detected using a FLIR-Teledyne optical gas imaging camera.

View the map "Details" tab below in the top right corner to learn more and access the data, or click on the map to explore the dynamic version of this data. Data sources are also listed at the end of this article.

In order to turn layers on and off in the map, use the Layers dropdown menu. This tool is only available in Full Screen view.

Items will activate in this map dependent on the level of zoom in or out.

View Full Size Map | Updated 8/21/2022 | Map Tutorial

Figure 1. Map of oil and gas drilling and production sites where leaks were detected using a FLIR-Teledyne optical gas imaging camera, model GF320. The icons on the map provide links to folders that house the recorded footage and DSLR imagery, as well as the complaint reports, for each site.

Health Considerations

It is most important to stress that the filmed emissions present an immediate risk to the frontline communities with homes and schools located near these drilling and production sites. The composition of volatilized emissions from crude oil and natural gas production has been thoroughly studied, and the presence of toxic and carcinogenic BTEX (benzene, toluene, ethylbenzene, and xylenes) chemicals is well established. Prolonged (chronic) exposure to BTEX compounds can affect the kidney, liver and blood systems. Long-term exposure to high levels of the benzene compound can lead to leukemia and cancers of the blood-forming organs. These chemicals are also neurotoxins and respiratory and skin irritants. While in the field at urban drilling sites, the thermographer and colleagues regularly experienced burning eyes, headaches, nausea, difficulty breathing, and fatigue. In addition to local health impacts, these chemicals also degrade regional air quality and are known to be elevated near oil and gas production in California. They are also precursors to ground level ozone, the main component of smog, as well as being potent greenhouse gasses. In addition to respiratory irritation and cancer risk from BTEX compounds, ground level ozone can reduce lung function causing a variety of health problems including chest pain, coughing, throat irritation, and congestion, and it can exacerbate bronchitis, emphysema, and asthma.

In response to pressure from grassroots organizations and frontline communities Governor Newsom ordered CalGEM to start a public health rule-making process. That was nearly three years ago. Since then CalGEM has released a regulatory proposal that includes a combination of engineering protections and a public health setback for new drilling permits. Setbacks are buffer zones that act as a type of zoning ordinance to prevent the development or expansion of industrial and extractive industries within sensitive use areas. California is the only major oil extraction state without a public health setback for oil and gas drilling. While the draft rulemaking is a good start, its one major shortcoming is that it applies only to the drilling of new wells – it does not apply to redrilling and reworking of wells on existing wellpads, which composes three quarters of all drilling activity since the beginning of 2021 (75.4%). As of this writing, Governor Newsom is proposing legislation that would enact the 3,200-foot setback into statute and apply it to redrilling and reworking in addition to new wells, as part of a larger end-of-session climate package proposal.

Leaking Idle Wells

California's aging oil and gas infrastructure is in a state of disrepair. As oil and gas infrastructure and wellheads age, new leaks and emission sources appear. For example, state regulators recently identified 49 leaking idle wells in May (2022) following a complaint submitted by FracTracker on behalf of a community concerned over one possibly leaking well in their east Bakersfield neighborhood (see Appendix A for dataset from CalGEM). The discoveries of these leaks coincided with the news that inspectors at the state regulatory office, the California Department of Geological Energy Management (CalGEM), were conducting thousands of inspections remotely—from their offices rather than actually being present at the well-sites. Following the reporting of the 49 leaking wells in Bakersfield in May, FracTracker visited Bakersfield in June and inspected idle wells using a FLIR optical gas imaging sensor/camera. The results of that field trip included the identification of additional leaking wells discovered by FracTracker.

While the August field investigation did not discriminate between active and idle drilling sites, particular attention remained focused on inspecting idle wells. As oil wells and production infrastructure at drill-sites age, pipe connections loosen, teflon tape degrades, flange connections fail, bushings harden, and rust corrodes and degrades equipment. These issues eventually occur at all drilling sites whether wells are actively producing oil and gas or sitting idle, resulting in leaks. In many cases human error also plays a role. Additionally, idle wells do not receive the same amount of attention or maintenance from operators as active operations, and a lack of inspections from CalGEM and local air districts at these sites have resulted in high counts of leaking wells.

Building upon the 49 leaking idle wells identified by CalGEM in Bakersfield (See Appendix A), this field trip identified an additional 21 leaking idle wellheads previously unreported. This count includes the identification of eight leaking wells in Kern County and six near Bakersfield not previously identified by CalGEM. Two of the wells are operated in the Fruitvale field by Sunray petroleum, the same operator as a portion of the leaking idle wells identified in east Bakersfield. FracTracker discovered two more leaking wellheads operated by Sequoia Exploration, Inc. in the City of Arvin, located downtown in the city park, next to a playground and an elementary school. In Los Angeles, 15 leaking wellheads at idled urban drilling sites were filmed leaking methane and VOCs in the neighborhoods West Carson (Torrance field) and Signal Hill (Long Beach field). A table summarizing the counts of leaking wells and infrastructure discovered in each district is presented below.

District	Leaking Idle* Wells	Uncontrolled Tank Emissions	Flares	Active Wellheads	Combustors
South Coast AQMD	15	19	1	1	8
San Joaquin Valley APCD	6	14	2		
Ventura County APCD		2		1	
Total	21	35	2	2	8
	*Includes marginally producing				

Table 1. Summary of the counts of documented leaks and emission sources by facility type.

Contractor Activity

It is very likely that the actual count of leaking idle wells discovered by regulators since May is much higher than reported by the agency. As we previously reported in the coverage of FracTracker's June field work, many of the idle wells inspected by FracTracker had recently received maintenance from oilfield contractors. This maintenance work was not limited to Bakersfield. Many of the wells visited throughout Kern County and Ventura County had clear indications of maintenance and repair efforts, including new pressure gauges, new stainless caps, new teflon tape, and replaced nuts and bolts.

As was reported by CalGEM, this work was paid for directly by the agency, with the possibility of recouping costs from operators in the future. FracTracker is supportive of CalGEM for taking these measures to shore up the highest risk sites, but it is troubling that it required an environmental health emergency to begin this work. While the immediate maintenance and remediation work by contractors hired by CalGEM was limited to just the leaking wells identified in east Bakersfield, it is clear that regulators at CalGEM understood the widespread and systemic nature of the risk of leaking idle wells. That is why CalGEM began hiring contractors to complete this work at a handful of sites in Kern County, and possibly in other parts of the state as well.

Missing Spill and Leak Reports

Evidence from the field investigation indicates that there have been numerous leaks that were never reported as required under state law. FracTracker suspects that the count of idle wells determined by CalGEM contractors to be leaking (since the initial discovery of the leaking Bakersfield wells in May) has not been publicly disclosed. During this August field trip FracTracker inspected over 300 individual wellheads. While this number may sound high, it was actually very limited in scope to wells that were accessible and those located within communities and near homes as a matter of prioritization. The vast majority of the idle wells inspected had clear signs of very recent maintenance and remediation of varying pieces of infrastructure at each wellhead. This was consistent in both Kern and Ventura Counties, but not in Los Angeles. This type of maintenance service is not conducted blindly, as there are many small pieces of equipment on a wellhead that can leak (examples are shown in the story map below).

It is most likely that contractors had identified leaks and replaced the leaking equipment on these idle wells. These leaks, like the majority of the leaking wells initially identified in Bakersfield in May, were never reported to the California Office of Emergency Services (CalOES) as is protocol for all spills including vapor leaks, neither were they reported on the CalGEM website for the public. The webpage still lists just 41 leaking wells, while their dataset provided to community advocacy groups identifies 49 (see Appendix A). When FracTracker reached out to CalGEM for a list of wells identified as leaking by contractors, or even the list of wells remediated by contractors who were paid by CalGEM, we were informed that records with that information are not maintained. Without releasing these records CalGEM is effectively suppressing crucial data on the incidence rate of leaking idle wells, which other researchers have estimated is 65%, but may be much higher. In a state where the California Council on Science and Technology estimates the existence of nearly 70,000 idle and another 5,500 already orphaned wells, this information on leakage rates is vital.

Tanks

In addition to leaking idle wells, tanks continue to be a predominant source of VOC emissions in frontline communities. This remains true even though tank emissions are technically addressed by state regulations, and some districts such as the south coast even have their own additional regulations. Tanks were present at the majority of the nearly 100 drilling sites visited and inspected by FracTracker. Inspections with the OGI camera revealed uncontrolled tank emissions at 35 drilling sites, including 19 in Los Angeles County, 14 in Kern County, and two facilities in Ventura County. Like wells, these tanks are a major hazard for communities as the emissions include BTEX chemicals and other toxic and carcinogenic VOCs. Additionally, tanks are an explosive hazard. Methane and other hydrocarbons are often emitted at flammable concentrations, making these emissions streams a major explosive hazard similar to the risk documented at the leaking wellheads in Bakersfield in May.

Tanks on oil and gas drill sites typically include wash tanks and stock tanks. Wash tanks are a sort of separator, washing water and brine from the oil before it's sent to a stock tank, where crude oil is stored onsite. These tanks are engineered to operate at or near atmospheric pressure, but pressure regularly builds up in the headspace of the tanks. This is the result of the produced fluid or crude oil off-gassing VOCs and other hydrocarbons, possibly due to particularly gassy production in some cases or otherwise due to increasing temperatures as the tanks heat up in the afternoon sun. Tank emissions are therefore typically documented from pressure-vacuum vents or hatches, which open as a safety mechanism to prevent tanks from exploding. This can occur when tanks either do not have vapor recovery systems or the vapor recovery system is not operating properly. At many of the sites, however, the tanks were damaged from some physical trauma or badly corroded and no longer air-tight.

Regulations

California Air Resources Board Regulations

At the state level, the California Air Resources Board's (CARB) regulates greenhouse gas emissions, including methane, from oil and gas production facilities (California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities). These restrictions, however, are insufficient because of numerous loopholes, reliance on industry's self-reporting, and lack of enforcement.

One major loophole in the CARB rules exempts many of the leaking tanks observed in this field investigation from installing the necessary equipment that reduces community exposure by capturing and controlling the emissions. The equipment, known as vapor recovery devices and systems are required only for separator and tank facilities that receive an average of more than 50 barrels of crude oil or condensate per day.

While small production facilities are still regulated to prevent emissions, they are exempt from the requirement of installing vapor recovery systems. In addition, the regulations for small facilities suffer from twin flaws that create a major loophole for many oil fields and smaller leaks that can accumulate. The first flaw exempts oil wells and production facilities that produce crude oil with an absolute gravity value (API) of less than 20. As much of the oil produced in the central valley is low quality tar-like crude, many wells qualify for this exemption. This includes all of the wells CalGEM found to be leaking in Bakersfield.

The second flaw is that leaks below 1,000 ppm are not actionable, and the accumulation of numerous smaller leaks at production facilities presents a risk of chronic exposure for frontline communities. For those oil wells that can be regulated (producing crude with an API > 20), the small producer rules are based on the concentration of methane in the leak. While this does not take into account the actual mass or volume of methane escaping, it allows inspectors to levy violations based on methane concentration measured with a simple methane detection device. The extent of the violation is determined by the concentration of methane with several actionable requirements based on concentration thresholds. The lowest threshold begins at a concentration of over 1,000 ppm and requires operators to fix the leak or stop the emissions, up to a minimum of 50,000 ppm that results in immediate fines, violations, and a suspension of production until the issue is resolved. Leaks under 1,000 ppm receive no response from the districts and are allowed to accumulate.

As a result of these loopholes, the majority of the inspected well-sites could be exempt from this section of the CARB rule given the following conditions: if the tank receives less that 50 barrels per day and the leak is below the 1,000 ppm methane threshold, or if the oil produced is considered heavy crude.

Local Air District Regulations

In addition to state regulations, certain individual air districts have adopted their own regulations. The South Coast Air Quality Management District (SCAQMD), for example, regulates emissions from nearly 8,500 operational oil wells and has additional rules at the local level to close these loopholes for small producer sites. The SCAQMD requires vapor recovery systems for all oil and gas facilities in the district versus this requirement for just large producer sites statewide. These additional local emissions regulations cover all facilities with tanks larger than 471 barrels (Rule 463) and emissions from all small producer sites [1148.1(D)(8)] as well, whereas the state regulations only apply to larger tanks. In contrast, the San Joaquin Valley Air Pollution Control District has jurisdiction over more than 82,000 operational wells, but does not have additional rules to regulate these emissions sources.

CalGEM Regulations

While the air districts have limited jurisdiction over certain emissions scenarios, CalGEM maintains a more thorough jurisdiction that is up to the interpretation and implementation of the agency’s Supervisor. According to the California public resources code, the agency is tasked with inspecting wells and tanks, issuing remediation orders, reporting leaks to OES, and ordering plugging where there’s any unreasonable waste of gas. CalGEM also has the jurisdiction to require wells to be plugged and abandoned if they leak “natural gas”, stating “The blowing, release, or escape of gas into the air shall be prima facie evidence of unreasonable waste.” and “an order shall be made by the supervisor directing that the unreasonable waste of gas be discontinued or refrained from to the extent stated in the order.” (Public Resources Code section 3300 and 3308.) CalGEM should require oil companies to plug these leaking idle and marginally producing wells, but has not yet leveraged this tactic. As a result new leaks will continue to occur as these facilities continue to age and decay.

VOC Combustors

Operators have several options to deal with the hydrocarbons collected by vapor recovery systems. They can be injected back into the ground, sold to market, or combusted. Since the market for natural gas is so poor, and it costs money to inject it, most operators choose to just burn it. While the state CARB rules allow for simple flares and low-NOX incinerators to just burn it, the SCAQMD requires that operators use the gas and vapors as a fuel source. Operators therefore use it to fuel Raypak heaters, boilers, and other combustion devices. These combustion devices do not require permits as long as they qualify for the Rule 219(n) low NOX exemption. The district requires the devices meet a minimum destruction threshold of 95% of the methane in the fuel source, but according to the SCAQMD, the efficiency of the devices have never been tested.

The exhaust streams of the various VOC combustors inspected during the field trip were often concentrated in non-combusted methane and VOCs. FracTracker identified eight facilities where methane and VOCs were documented in the exhaust streams from combustion devices, and the plumes of exhaust were traveling over the fencelines of the facilities and into frontline communities. These nine facilities were therefore included in the list of complaints submitted to air district regulators, for their inefficient combustion devices. Additionally, three flares were reported as complaints; two in Kern that were burning inefficiently and one in the Santa Fe Springs field of Los Angeles that was unlit but still releasing emissions. Examples of complaints submitted for combustor exhaust and flares are provided in the storymap below, along with other complaints representative of the various categories of leaks discussed above (See also Table 1).

The Take Away

Leaks and uncontrolled emissions are a common occurrence for oil and gas infrastructure in California. This includes both active production drill sites and aging idled wells. The lack of oversight of idle wells by operators and regulators has resulted in leaks from the wellheads of idle wells becoming a systemic issue throughout California that has been ignored for decades. FracTracker's field work shows that this is also the case for active tanks at drilling sites and collection facilities. While regulations exist to address tank emissions and leaking idle wells, inspections of these facilities have not been occurring. Additionally, active sites have not been required to meet the standards of the "new" emissions regulations, passed in 2017 and fully implemented in 2019. Furthermore, many of the tank facilities visited were repeat offenders, and uncontrolled emissions were documented at the same facilities and sometimes from the same exact sources as reported by FracTracker to the local air districts in previous years.

The systemic nature of these documented leaks is not an issue that can be addressed with engineering controls. When one leak is fixed, another often emerges shortly after, as the aging infrastructure has many fail points. New regulatory loopholes, such as venting through VOC combustors, also create new sources of emissions rather than actually reducing exposures. The only solution is to plug the wells and remediate the drilling sites. FracTracker urges the legislature and Governor Newsom's administration to plug all idle wells, and develop protective public health setbacks of at least 3,200' that include all existing wells and oil production infrastructure.

For questions please contact:

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References & Where to Learn More

This dataset was provided by CalGEM (see Appendix A). It identifies the 49 idle wells determined to be leaking and provides data on the status of the leaks at the time of the dataset distribution (July 2022). The initial well inspections conducted by CalGEM occurred in May 2022.

Appendix A. Dataset of leaking Bakersfield wells from CalGEM

API	Well Designation	Operator	Well Issue	Repair Status	lat	lon
402908759	Needham-Bloemer1	Citadel Exploration Inc.	Leaking methane	Repaired	35.41319656	-118.913414
402908763	Needham-Bloemer14	Citadel Exploration Inc.	Leaking methane	Repaired	35.41439819	-118.9119186
402908770	Needham-Bloemer25	Citadel Exploration Inc.	Leaking methane	Repaired	35.41563797	-118.9134445

402908775	Needham-Bloemer30	Citadel Exploration Inc.	Leaking methane	Repaired	35.41637039	-118.9084015
402908776	Needham-Bloemer31	Citadel Exploration Inc.	Thought to be Leaking methane (6/2/2022)	Multiple subsequent in-person inspections found no leak	35.41379929	-118.9126511
402908779	Needham-Bloemer35	Citadel Exploration Inc.	Leaking methane	Repaired	35.41497421	-118.9098663
402957338	Needham-Bloemer38	Citadel Exploration Inc.	Leaking methane	Repaired	35.41376495	-118.9095306
402908761	Needham-Bloemer4	Citadel Exploration Inc.	Leaking methane	Repaired	35.41322708	-118.9089813
403062148	Needham-Bloemer Shakedown St#2	Citadel Exploration Inc.	Leaking methane	Repaired	35.41404343	-118.9091186
402908771	Needham-Bloemer26	Citadel Exploration Inc.	Thought to be Leaking methane (6/2/2022)	Multiple subsequent in-person inspections found no leak	35.41560364	-118.9119721
402908772	Needham-Bloemer27	Citadel Exploration Inc.	Leaking methane	Repaired	35.41561127	-118.9104233
402908773	Needham-Bloemer28	Citadel Exploration Inc.	Thought to be Leaking methane(6/2/2022)	Multiple subsequent in-person inspections found no leak	35.41562653	-118.9089966
402988951	Needham-Bloemer72	Citadel Exploration Inc.	Leaking methane	Repaired	35.41594315	-118.9096222
403063440	Needham-Bloemer Thunderstruck #4	Citadel Exploration Inc.	Thought to be Leaking methane(6/2/2022)	Multiple subsequent in-person inspections found no leak	35.41378494	-118.9055454
402908789	Bloemer10	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.40114975	-118.9045486

402969434	Bloemer120	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.40114594	-118.9039917
402908792	Hood-Bloemer1A	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.40294647	-118.9045715
402971724	Hood-Bloemer108D	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.40281296	-118.9048996
402908794	Hood-Bloemer3A	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.40209579	-118.9037552
402969433	Hood-Bloemer109	Sunray Petroleum, Inc.	Leaking methane	Repaired	35.40238571	-118.9041824
402908871	Afana1	Zynergy, LLC	Leaking methane	Repaired	35.40583801	-118.9111633
402951205	Afana12	Zynergy, LLC	Leaking methane	Repaired	35.4074173	-118.9112854
402908872	Afana2	Zynergy, LLC	Leaking methane	Repaired	35.40714264	-118.9134827
402908873	Afana3	Zynergy, LLC	Leaking methane	Repaired	35.40582657	-118.9100189
402973711	Afana5V	Zynergy, LLC	Leaking methane	Repaired	35.40628433	-118.9093628
402908879	Afana9	Zynergy, LLC	Leaking methane	Repaired	35.4086647	-118.9136581
402908877	Afana7	Zynergy, LLC	Leaking methane	Repaired	35.408647	-118.9137581
402906740	K.C.L. B52	Griffin Resources	Leaking methane	Repaired	35.3664856	-119.063652
402908238	K.C.L. A53	Griffin Resources	Leaking methane	Repaired	35.3637619	-119.0643768
402908241	K.C.L. A84	Griffin Resources	Leaking methane	Repaired	35.3622818	-119.0577545
402908242	K.C.L. B61	Griffin Resources	Leaking methane	Repaired initially; evidence of low level leak; repair work to continue	35.36774063	-119.0621414

402908257	K.C.L. D87	Griffin Resources	Leaking methane	Repaired	35.35753632	-119.0571823
402900741	K.C.L. D77	Griffin Resources	Leaking methane	Repaired	35.35693741	-119.0599976
402908243	K.C.L. B62	Griffin Resources	Leaking methane	Repaired	35.3657608	-119.0621414
402908246	K.C.L. B73	Griffin Resources	Leaking methane	Repaired	35.36410904	-119.0599594
402908251	K.C.L. D67	Griffin Resources	Leaking methane	Repaired	35.35692215	-119.0621338
402908252	K.C.L. D75	Griffin Resources	Leaking methane	Repaired	35.36050415	-119.0599365
402908258	K.C.L. D88X	Griffin Resources	Leaking methane	Repaired	35.35635757	-119.0573959
402908245	K.C.L. B72	Griffin Resources	Leaking methane	Repaired	35.36588669	-119.0598526
402908239	K.C.L. A64	Griffin Resources	Leaking methane	Repaired	35.36230087	-119.062233
402908259	K.C.L. A78-4	Griffin Resources	Leaking methane	Repaired	35.36153412	-119.059021
402906770	10	E&B Natural Resources	High Pressure	Repaired	35.36511993	-119.0551834
402906772	12	E&B Natural Resources	High Pressure	Repaired	35.36001205	-119.0553207
402906773	14	E&B Natural Resources	High Pressure	Repaired	35.35935974	-119.0555573
402906762	2	E&B Natural Resources	High Pressure	Repaired	35.36949158	-119.0554733
402906763	3	E&B Natural Resources	High Pressure	Repaired	35.36408997	-119.0555344
402906765	5	E&B Natural Resources	High Pressure	Repaired	35.36592102	-119.055542

402906766	6	E&B Natural Resources	High Pressure	Repaired	35.36047745	-119.055542
402906769	9	E&B Natural Resources	High Pressure	Repaired	35.36504364	-119.055542

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Larson says:
July 11, 2023 at 7:41 am
This detailed report on leaking idle wells, especially in Bakersfield, California, drives home the crucial need for improved oversight on our aging oil and gas infrastructure. The fact that numerous leaks were discovered remotely, and potentially many more unreported, demands greater transparency from regulatory bodies. We should be particularly concerned about VOC-emitting tanks at drilling sites, given their significant environmental and public health implications. Bakersfield, unfortunately, stands out in this situation, underscoring the urgent need for action.

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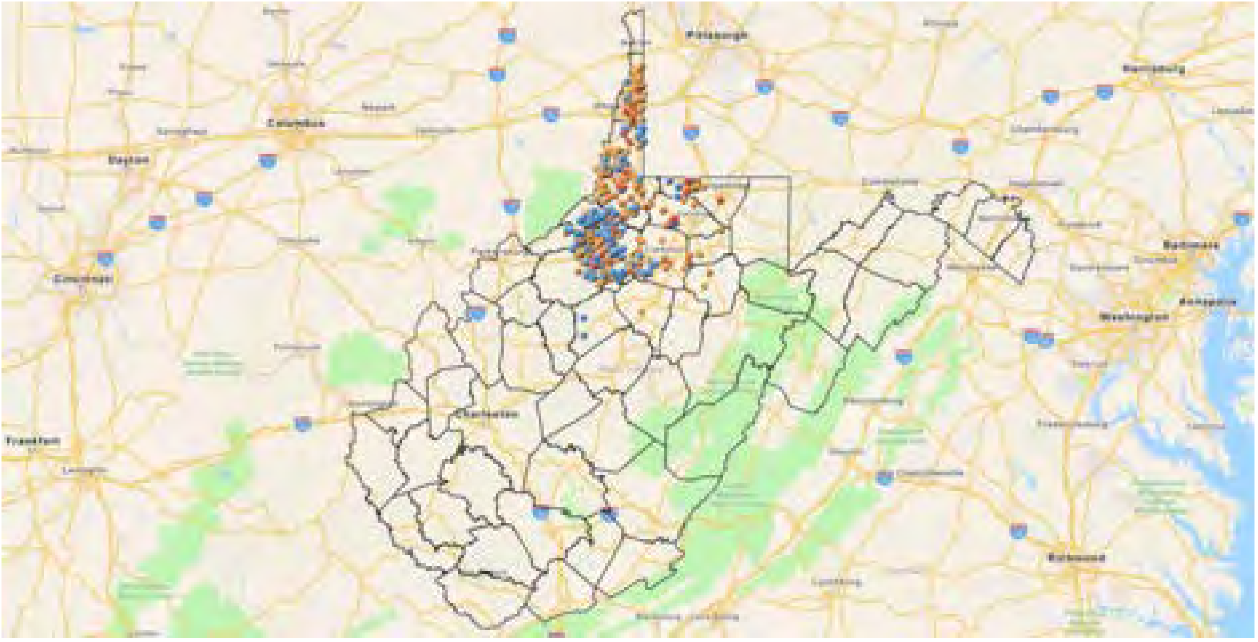

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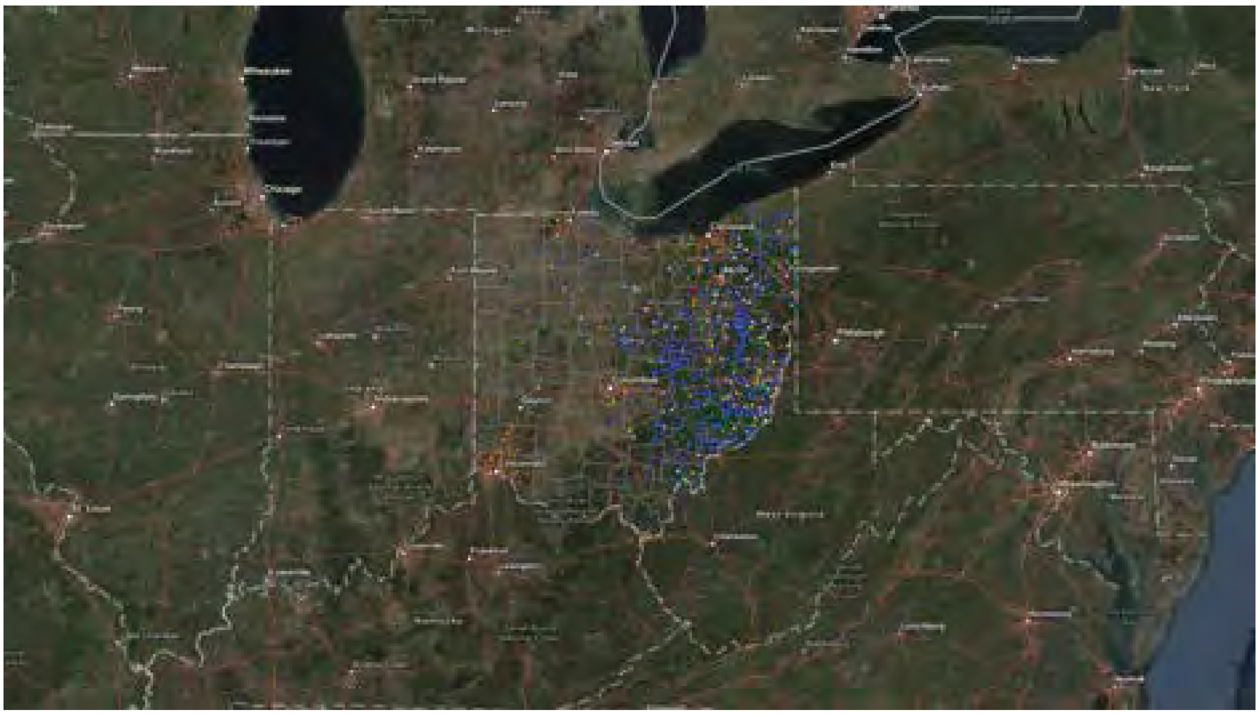

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The cottage along Slope Creek, months after being vacated due to health concerns caused by nearby oil and gas operations. Photo courtesy of Chloe Mankin

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November 9, 2023

An exploration of factors related to oil and gas activity that could contribute to the history of house explosions in Plum Borough, Pennsylvania.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/10/RusticRidge_102023.jpg 1119 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2023-11-09 19:01:252023-12-11 17:47:12Why Do Houses Keep Exploding in One Pennsylvania Suburb?

FracTracker Alliance Releases Statement Opposing Governor Shapiro’s Agreement With CNX

November 7, 2023
/

0 Comments
FracTracker Alliance Executive Director Shannon Smith releases statement in opposition to Pennsylvania Governor Josh Shapiro's agreement with natural gas company CNX.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/02/Delaware-River-Feature-with-FracTracker-Logo.jpg 667 1500 FracTracker Alliance https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png FracTracker Alliance2023-11-07 11:00:272023-11-07 16:49:33FracTracker Alliance Releases Statement Opposing Governor Shapiro’s Agreement With CNX

Oil and Gas Activity Within California Public Health Protection Zones

October 4, 2023
/

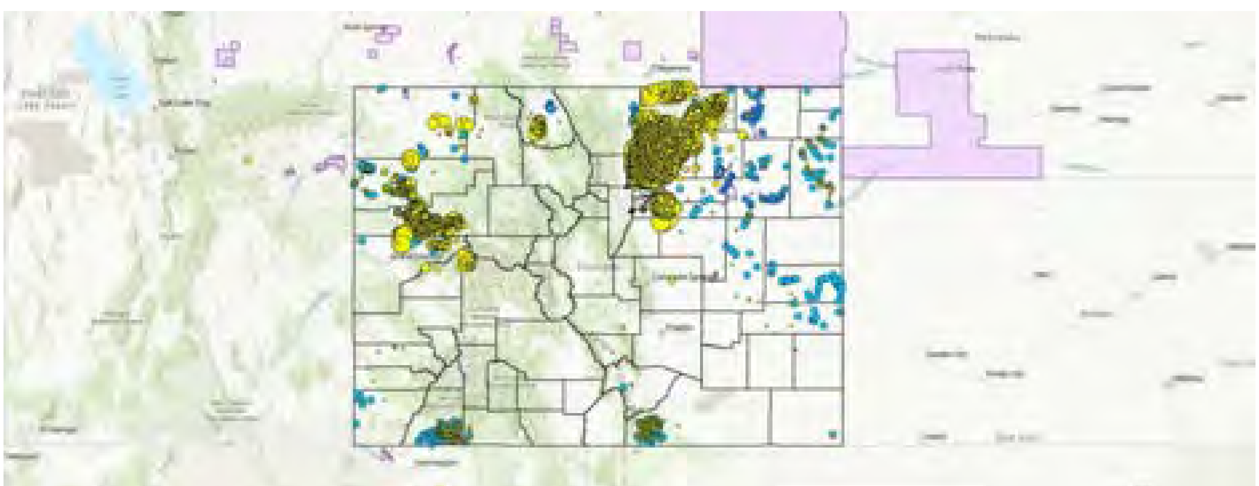
0 Comments

Assessment shows hundreds of sensitive receptor sites located within 3,200 feet of operational oil and gas wells in California would have been protected if California Senate Bill 1137 had not been challenged by referendum.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/10/Wells-Within-3200-Feet-of-Schools-Childcare-CA.jpg 595 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2023-10-04 16:38:472023-10-04 21:19:54Oil and Gas Activity Within California Public Health Protection Zones

Assessment of Oil and Gas Well Ownership Transfers in California

May 18, 2023
/

0 Comments
A report by FracTracker Alliance finds that more comprehensive bonding requirements are necessary to protect the state of California from being left financially accountable for the plugging and abandonment of tens of thousands of orphaned oil and gas wells.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/05/Well-transfers-in-CA.jpg 518 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2023-05-18 08:05:582023-05-18 08:14:02Assessment of Oil and Gas Well Ownership Transfers in California



Evaluation of the Capacity for Water Recycling for Colorado Oil and Gas Extraction Operations

May 2, 2023
/

0 Comments
A report by FracTracker Alliance finds Colorado’s oil and gas industry has produced enough wastewater statewide to completely satisfy the current and past needs of source water for hydraulic fracturing completions.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/05/Colorado-Water-Use-5.2.23.jpg 589 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2023-05-02 12:33:532023-06-02 11:35:52Evaluation of the Capacity for Water Recycling for Colorado Oil and Gas Extraction Operations

Sarah Carballo, FracTracker Alliance, 2022

Evidence Shows Oil and Gas Companies Use PFAS in New Mexico Wells

April 27, 2023
/

0 Comments
A new report released by Physicians for Social Responsibility (PSR) in April 2023 reveals that oil and gas companies have been using PFAS, a class of extremely toxic and persistent chemicals, in New Mexico since at least 2013.
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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/04/DSC_0855.jpg 1001 1500 FracTracker Alliance https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png FracTracker Alliance2023-04-27 13:46:002023-04-27 14:18:17Evidence Shows Oil and Gas Companies Use PFAS in New Mexico Wells

CalGEM Permit Review Q1 2023: Well Rework Permits Increase by 76% in California

April 14, 2023
/

0 Comments
In Q1 2023, the California Geologic Energy Management Division (CalGEM) gave out 896 rework permits to oil companies. More than half of these permits were for wells located within 3,200 feet of homes, schools, or healthcare facilities.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/04/Rework-Permits-Feature-Image.png 506 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2023-04-14 11:36:392023-04-28 16:05:23CalGEM Permit Review Q1 2023: Well Rework Permits Increase by 76% in California

Ted Auch, FracTracker Alliance, 2022

2022 Pipeline Incidents Update: Is Pipeline Safety Achievable?

February 1, 2023
/

0 Comments
This analysis provides a top-level summary of pipeline incidents reported to the Pipeline and Hazardous Materials Safety Administration (PHMSA) and examines whether or not safe oversight of the industry is possible.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/02/DSC_1026_LowRes.jpg 1000 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2023-02-01 15:36:182023-02-01 17:01:372022 Pipeline Incidents Update: Is Pipeline Safety Achievable?

Testimony On EPA's Proposed Methane Pollution Standards for the Oil and Gas Industry

January 31, 2023
/

0 Comments
FracTracker Alliance supports strong federal methane rules and urges further improvements that are needed to curb dangerous methane emissions.
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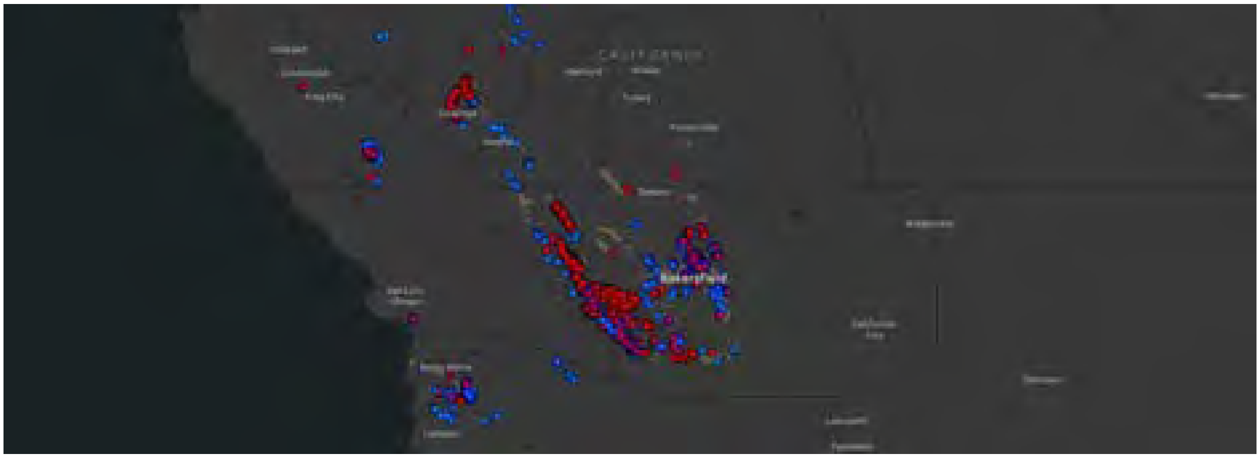
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2020/09/Methane_Air_WaterQualityConcerns-1.jpg 534 800 FracTracker Alliance https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png FracTracker Alliance2023-01-31 15:01:342023-02-27 16:43:15Testimony On EPA's Proposed Methane Pollution Standards for the Oil and Gas Industry



Assessment of Rework Permits on Oil Production from Operational Wells Within the 3,200-Foot Public Health Protection Zone

January 24, 2023
/

0 Comments
This analysis shows that the policy proposed in SB 1137 of denying rework permits within the health protection zones is a commonsense public health intervention that would have minimal effects on production within the protection zone.
Read more
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CalGEM Permit Review Q4 2022: Oil Permit Approvals Show Steep Rise Within Protective Buffer Zones

January 18, 2023
/

0 Comments
During the fourth quarter of 2022, California regulator CalGEM issued oil and gas operators 222 new drilling permits, an increase of over 750% compared to the fourth quarter of 2021. Of those, nearly half (100; 47%) were for wells located within the 3,200’ public health setback zone.

Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2023/01/CalGEM-Q4-2022-Permit-Review.jpg 570 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2023-01-18 18:01:532023-01-18 18:03:23CalGEM Permit Review Q4 2022: Oil Permit Approvals Show Steep Rise Within Protective Buffer Zones

A Contentious Landscape of Pipeline Build-outs in the Eastern US

November 30, 2022
/

1 Comment
In this article, we'll feature four contentious pipeline build-outs in the Eastern United States, show ways in which those pipelines impact natural and human communities, and provide examples of how environmental advocates have challenged these projects, with varying degrees of success.
Read more
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Major Gas Leak Reveals Risks of Aging Gas Storage Wells in Pennsylvania

November 30, 2022
/

0 Comments
Following an enormous gas leak in Jackson Township, Cambria County Pennsylvania, we mapped oil and gas storage wells and fields throughout the state and found that the majority of Pennsylvania's storage wells were drilled prior to 1979, making them most vulnerable to well failures.
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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/11/Rager-Mountain-Feature.jpg 636 1500 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2022-11-30 14:12:222023-02-03 13:50:48Major Gas Leak Reveals Risks of Aging Gas Storage Wells in Pennsylvania

Coursing Through Gasland: A Digital Atlas Exploring Natural Gas Development in the Towanda Creek Watershed

November 23, 2022

This digital atlas exploring natural gas development in the Towanda Creek watershed is the fourth in a series of FracTracker Alliance watershed impact analyses in the Susquehanna River Basin.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/11/DSC_1359_HighRes.jpg 1000 1500 FracTracker Alliance https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png FracTracker Alliance2022-11-23 15:15:112023-03-03 10:28:05Coursing Through Gasland: A Digital Atlas Exploring Natural Gas Development in the Towanda Creek Watershed

Falcon Pipeline Online, Begins Operations Following Violations of Clean Streams Law

November 17, 2022
/

0 Comments
The Shell ethane cracker in Beaver County, Pennsylvania, and Falcon Pipeline begin operations following civil penalties from Pennsylvania regulators for violations of the Clean Streams Law.
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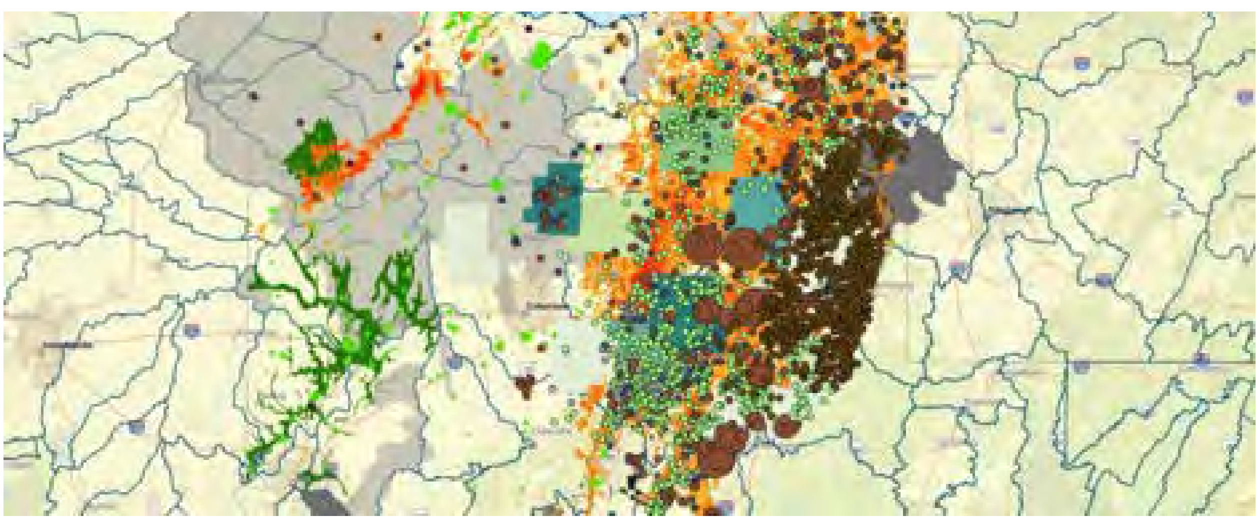
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/11/Fhn3YgeXkAI0QiX.jpg 675 1200 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2022-11-17 16:43:392022-11-18 13:41:39Falcon Pipeline Online, Begins Operations Following Violations of Clean Streams Law



Synopsis: Risks to the Greater Columbus Water Supply from Oil and Gas Production

October 31, 2022
/

1 Comment
A white paper by Columbus Community Rights Coalition (CCRC) will inform resident stakeholders of risks to the water associated with oil & gas production activities occurring within their watershed region of Columbus, Ohio.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/10/Columbus-Source-Water.jpg 605 1500 Guest Author https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Guest Author2022-10-31 21:39:022022-11-29 14:24:38Synopsis: Risks to the Greater Columbus Water Supply from Oil and Gas Production

Desalination: The Chemical Industry’s Demand for Water in Texas

September 19, 2022

Desalination facilities proposed by the petrochemical industry in Texas could significantly impact fragile Gulf Coast ecosystems.
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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/09/DSC_1021_LowRes__1607617394306__w1920-e1663613850641.jpg 667 1500 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2022-09-19 15:08:172022-11-03 11:56:26Desalination: The Chemical Industry’s Demand for Water in Texas

Take Action in Support of No New Leases

September 6, 2022

The federal government is accepting comments on a 5-Year Offshore Oil and Gas Lease Program. We need your voice to join in solidarity with communities in the Gulf and the Arctic and call for no new leases.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/06/LKrop_infrastructure-offshoredrilling-drillrigs-SantaBarbara-CA_EnvrDefenseCtr_Aug20131-e1663254826557.jpg 178 400 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2022-09-06 13:32:202022-09-15 11:14:03Take Action in Support of No New Leases

Carbon Capture and Storage: Developments in the Law of Pore Space in North Dakota

August 31, 2022

The interplay between the rights of the owner of the surface estate and the rights of the mineral estate have recently become the subject of both legislation and litigation as the use of subsurface pore space by various energy industries has developed at an increasingly rapid pace in North Dakota.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/08/51119572588_132e0366c1_k_1-e1663254774314.jpg 607 1364 Guest Author https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Guest Author2022-08-31 14:33:482022-09-15 16:29:45Carbon Capture and Storage: Developments in the Law of Pore Space in North Dakota

Carbon Capture and Storage: Industry Connections and Community Impacts

August 31, 2022

Industries that stand to capitalize on the proliferation of carbon capture and storage are aggressively pursuing its development despite its wide-ranging risks and diminishing returns for communities across the U.S.
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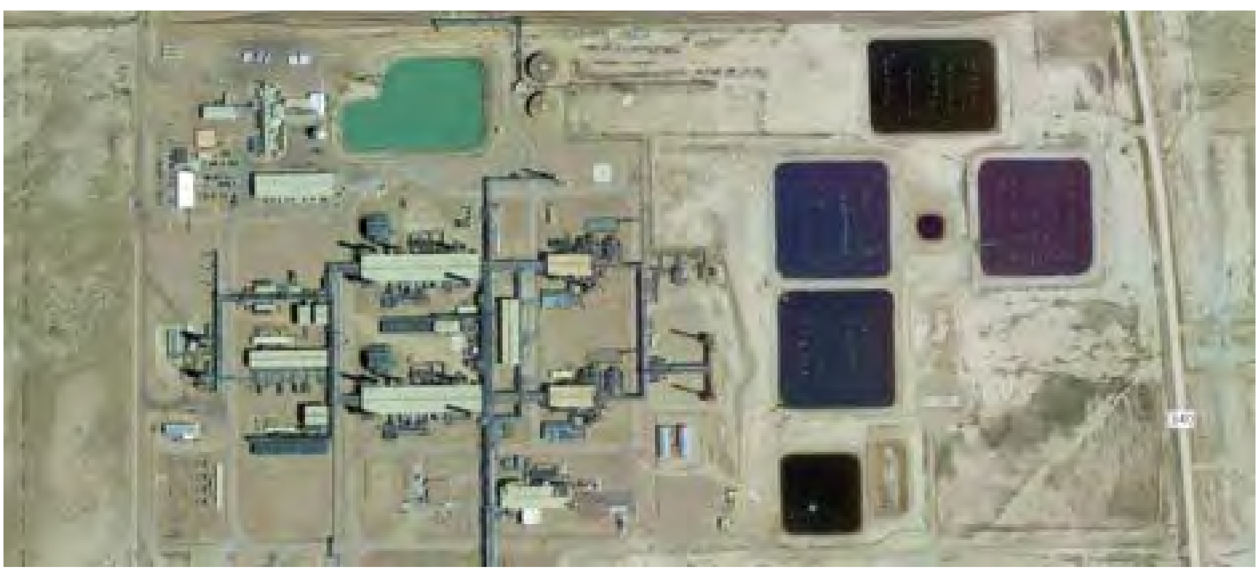

Carbon Capture and Storage: Fact or Fiction?

August 31, 2022

Extractive industry uses propaganda to protect private profits at the expense of the public interest. According to the evidence, there is reason to believe that carbon capture and storage (CCS) is one such scheme.

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Pipeline Right-of-Ways: Making the Connection between Forest Fragmentation and the Spread of Lyme Disease in Southwestern Pennsylvania

August 22, 2022
/

1 Comment
While many ecological factors may contribute to the spread of Lyme disease, two of the most significant factors are believed to be climate change and forest fragmentation. This study assesses the role that different pipeline construction proxies play in the change in average annual Lyme disease rate in Pennsylvania counties from 2001 to 2019.
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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/08/Auch_FracTracker-2021_Aerial-Support-by-Lighthawk-1-e1663254703246.jpg 608 1367 FracTracker Alliance https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png FracTracker Alliance2022-08-22 22:01:492022-09-15 11:11:54Pipeline Right-of-Ways: Making the Connection between Forest Fragmentation and the Spread of Lyme Disease in Southwestern Pennsylvania

August 22, 2022
/

1 Comment
FracTracker inspections of oil and gas infrastructure using an optical gas imaging camera found numerous sources of uncontrolled emissions in three California counties.
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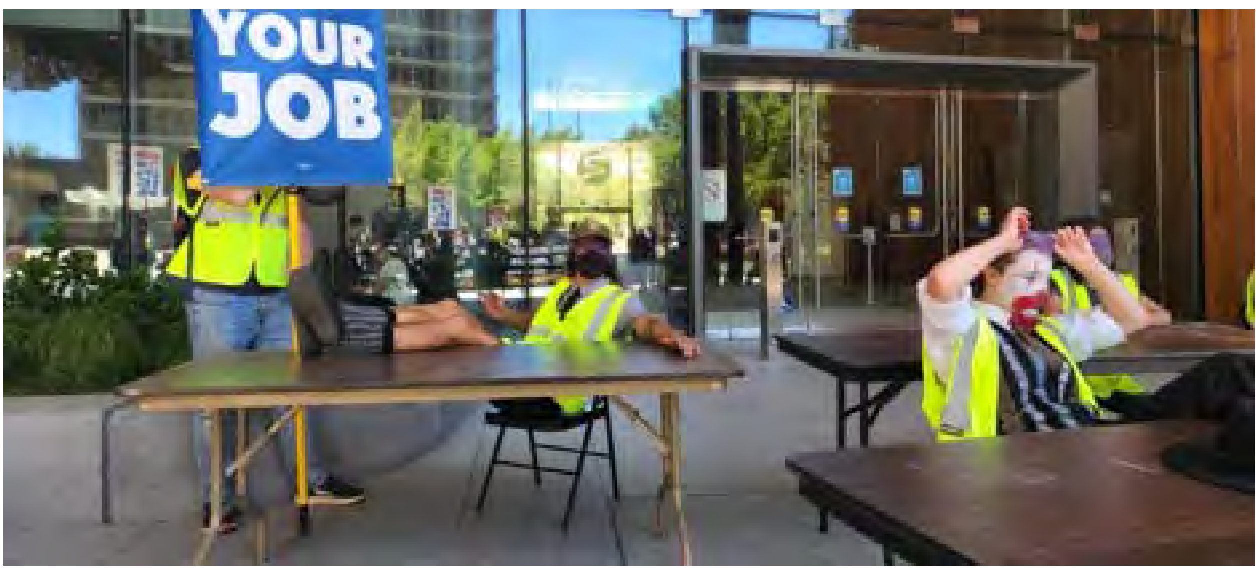
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/08/MOV_8837_Moment-e1663254387862.jpg 284 640 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2022-08-22 09:52:582022-09-15 11:06:37FracTracker Finds Widespread Hydrocarbon Emissions from Active & Idle Oil and Gas Wells and Infrastructure in California



California Regulators Approve More Oil Well Permits Amid a Crisis of Leaking Oil Wells that Should be Plugged

July 29, 2022

FracTracker's in-the-field inspections and updated analysis of CalGEM permit data shows that California's regulatory practices and permitting policies risk exposing frontline communities to VOCs from oil and gas well sites.
Read more

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An Insider Take on the Appalachian Hydrogen & CCUS Conference

June 23, 2022

Reflections on the Appalachian Hydrogen and Carbon Capture conference, and how companies hope to use new tech to prolong fossil fuel dependence
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Does Hydrogen Have a Role in our Energy Future?

June 21, 2022

There has been increasing focus on using hydrogen gas as a fuel, but most hydrogen is currently formed from methane, which could lead to more fracking.
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Oil and Gas Brine in Ohio

May 13, 2022
/

2 Comments
A hazardous byproduct of oil & gas operations, called “brine," poses a problem because of its radioactivity and the volumes produced.
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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/05/Brine-spreading-map-feature-1.jpg 667 1500 Guest Author https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Guest Author2022-05-13 16:19:112022-08-10 15:43:05Oil and Gas Brine in Ohio

PA Environment Digest Blog: Conventional Oil & Gas Drillers Dispose Of Drill Cuttings By ‘Dusting’

May 3, 2022
/

2 Comments
David Hess reports on the pervasive & dangerous practice of waste disposal at oil and gas well drilling sites via “dusting.”
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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/05/DustingHighVolDirtyFilter-feature.jpg 667 1500 Guest Author https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Guest Author2022-05-03 09:37:492022-05-03 09:37:49PA Environment Digest Blog: Conventional Oil & Gas Drillers Dispose Of Drill Cuttings By ‘Dusting’

Real Talk on Pipelines

April 28, 2022

This story map contains audio clips and quotes from local officials and residents on the impacts of oil & gas pipelines in their communities.
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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/04/TAuch_Cultural-Harvey_FamilyFarm_NEXUS_Pipeline-DTEEnergy_Enbridge-ChippewaLake_MedinaCounty_OH_May20183-feature.jpg 667 1500 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2022-04-28 14:12:552022-04-28 14:12:55Real Talk on Pipelines

2021 Production from Pennsylvania's Oil and Gas Wells

April 28, 2022
/

1 Comment
FracTracker has released an analysis of Pennsylvania's 2021 oil and gas production totals and the impacts of orphaned and abandoned wells.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/04/TAuch_Infrastructure-Compressor_Cryogenic_Complex-MarkWest_EnergyTransfer-WashingtonCounty-PA_Sept2021-feature.jpg 667 1500 Matt Kelso, BA
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2022-04-28 13:37:312023-03-09 14:03:402021 Production from Pennsylvania's Oil and Gas Wells

Mapping Energy Systems Impacted by the Russia-Ukraine War

April 20, 2022
/

1 Comment

This story map explores how the West's failure to transition from fossil fuels to renewable energy is funding Russia's invasion of Ukraine
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Dimock residents working to protect water from a new threat: fracking waste

April 11, 2022
/

2 Comments
Sen. Muth and Dimock, PA residents are fighting a permitted Eureka Resource Susquehanna facility that puts their water at risk.
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Implications of a 3,200-foot Setback in California

April 6, 2022

California is the only major oil state without a health and safety setback from fossil fuel activity. This article explores what a setback in California means for its people and environment.
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New Trends in Drilling Permit Approvals Take Shape in CA

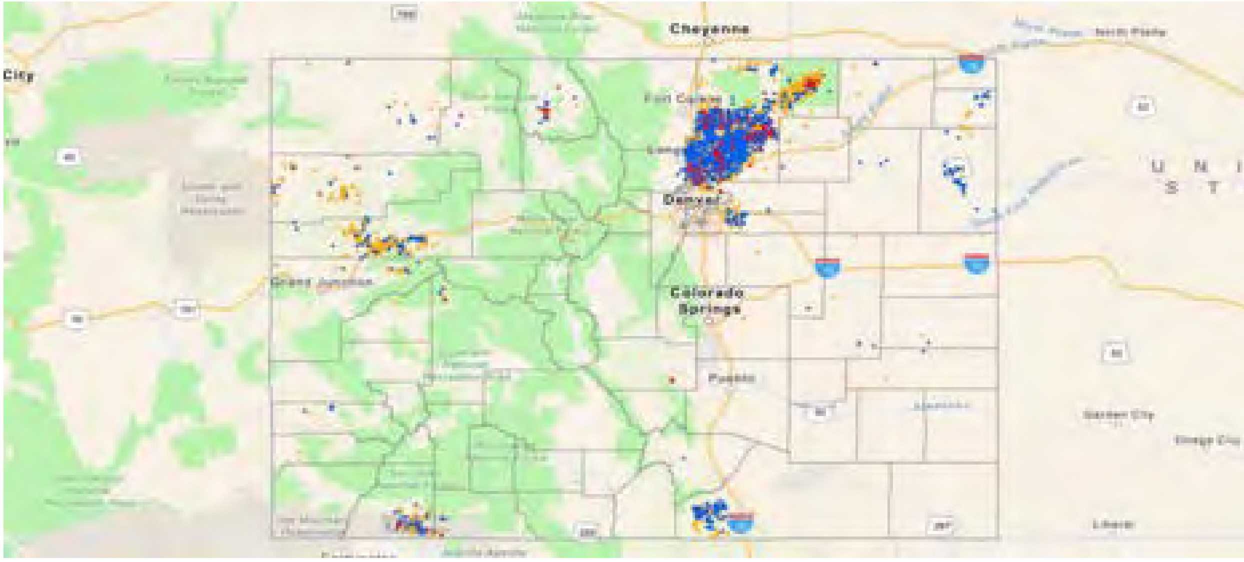
March 15, 2022
/

2 Comments
FracTracker's recent analysis finds that California's drilling permit approvals have slowed since last October, but not across the board. This trend only applies to permits for new drilling and enhanced oil recovery (EOR) wells.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/03/BLenker_infrastructure-oilrig-southLA-CA_Oct20173.jpg 795 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2022-03-15 16:32:032022-03-15 18:00:00New Trends in Drilling Permit Approvals Take Shape in CA

Oil and Gas Drilling in California Legislative Districts

March 14, 2022

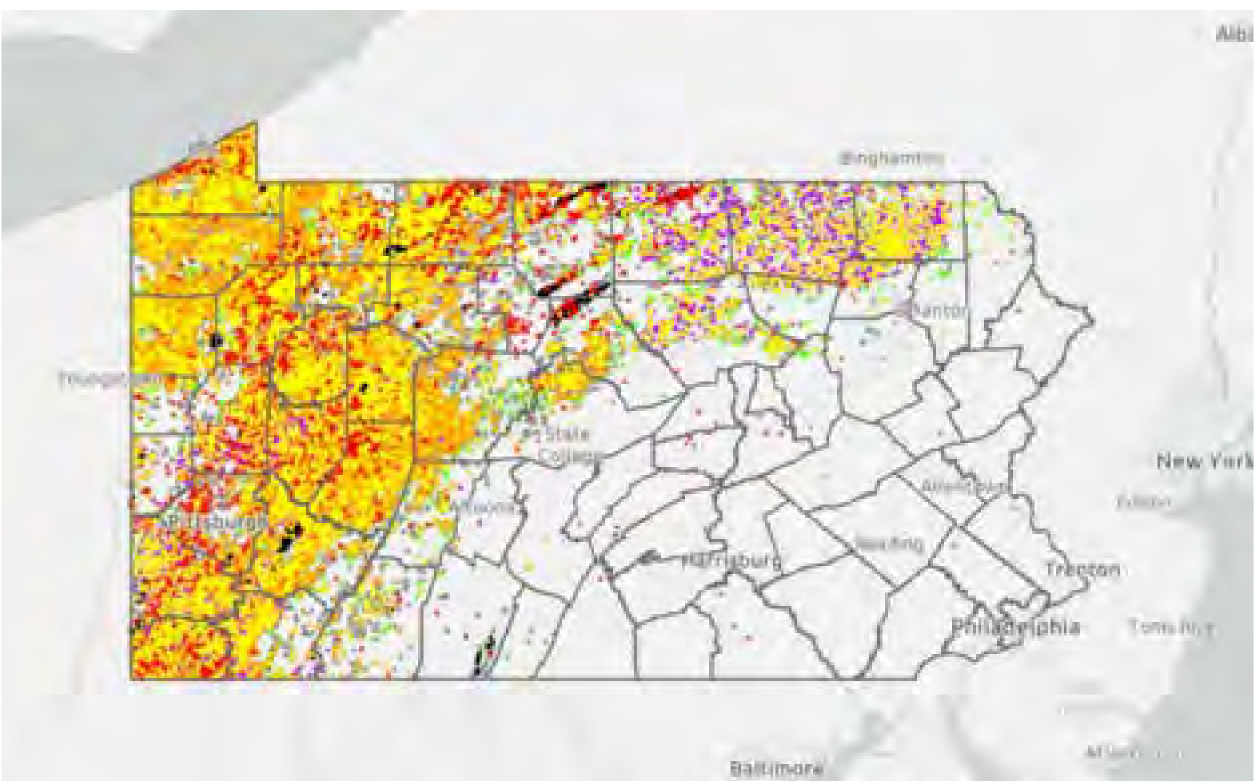
FracTracker has been working with grassroots organizations to inform legislators and locals about oil and gas extraction in their districts, including maps and tables of the infrastructure in their areas.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/03/KFerrar-CAlegislative-analysis_March2022.jpg 720 1280 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2022-03-14 15:18:402022-03-14 15:18:40Oil and Gas Drilling in California Legislative Districts



New Report: Fracking with “Forever Chemicals” in Colorado

January 31, 2022
/

1 Comment
A report by PSR provides evidence that oil and gas companies have been using dangerous PFAS "forever chemicals" in CO wells.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/01/PFAS-wells-in-Colorado-Feature.jpg 667 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2022-01-31 16:36:332022-01-31 16:36:33New Report: Fracking with “Forever Chemicals” in Colorado



Introducing: FracTracker’s comprehensive new Pennsylvania map!

January 20, 2022
/

4 Comments
FracTracker's new Pennsylvania oil and gas well map displays conventional and unconventional wells and violations as of January 12, 2022.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2022/01/FeatImage_MK.jpg 935 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2022-01-20 15:32:142022-01-20 15:32:14Introducing: FracTracker’s comprehensive new Pennsylvania map!

New Letter from Federal Regulators Regarding how the Falcon has Been Investigated

December 1, 2021

FracTracker received a letter from federal regulators with news on Shell's Falcon Pipeline investigation, but many concerns still remain.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/12/173695136_1422048161521006_7197500259062906334_n.jpg 667 1500 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2021-12-01 15:27:402021-12-01 15:27:40New Letter from Federal Regulators Regarding how the Falcon has Been Investigated

US Army Corps Muskingum Watershed Plan ignores local concerns of oil and gas effects

December 1, 2021
/

2 Comments
Local stakeholders' concerns about the environmental and health impacts of oil and gas in the Muskingum Watershed of Ohio have been minimized or excluded by the US Army Corps' environmental assessment.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/11/TAuch_Infrastructure-naturalgas-powerplant-construction-Caithness-GuernseyCounty-OH_April2021.jpg 667 1500 Guest Author
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Guest Author2021-12-01 15:20:152022-01-04 17:53:55US Army Corps Muskingum Watershed Plan ignores local concerns of oil and gas effects

Oil and gas companies use a lot of water to extract oil in drought-

stricken California

November 9, 2021
/

2 Comments
FracTracker details the disproportionate amounts of water used by the oil and gas industry in CA and recommends that Gov. Newsom take action.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/11/RMasoner-ChevronOilPumpJacks-SanJoaquinValley_2008.jpg 428 900 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-11-09 14:59:182021-11-09 21:31:59Oil and gas companies use a lot of water to extract oil in drought-stricken California

Southeastern Texas Petrochemical Industry Needs 318 Billion Gallons of Water, but the US EPA Says Not So Fast

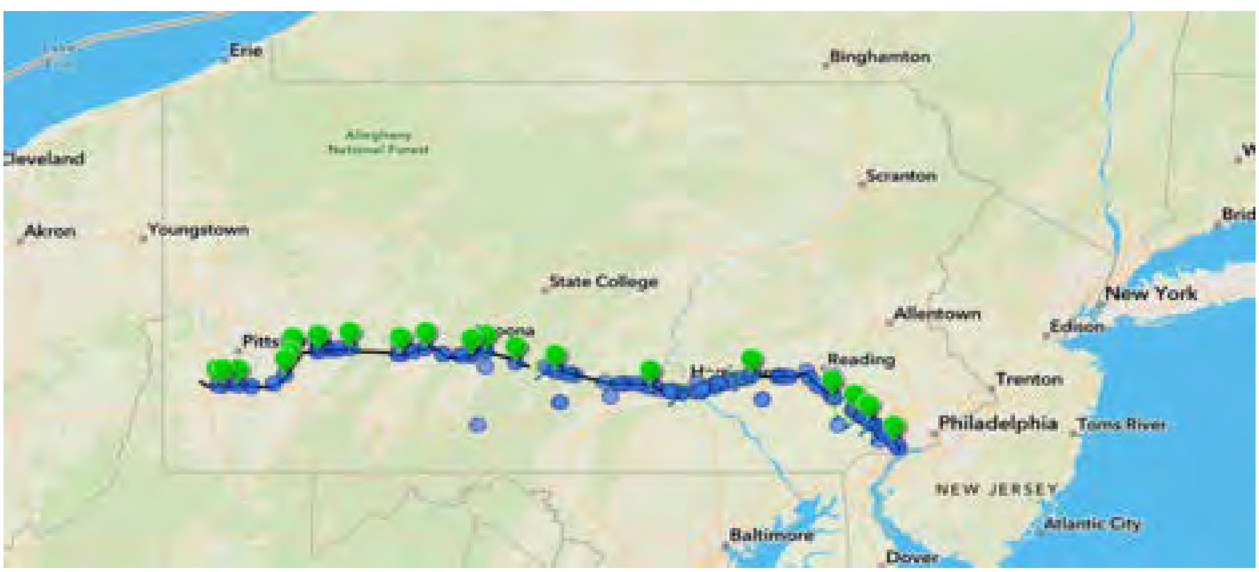
November 5, 2021

The US EPA is moving to turn off the tap to Texas' petrochemical operators that are demanding exorbitant water quantities where there are none.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/11/TAuch_Plastics_Refinery_TankFarm_Terminal-Trafigura_CorpusChristiPolymers_Valero_Citgo_FlintHillsResources-CorpusChristi_TX_LightHawk_Nov2019-feature.jpg 667 1500 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2021-11-05 09:43:472021-11-05 09:47:30Southeastern Texas Petrochemical Industry Needs 318 Billion Gallons of Water, but the US EPA Says Not So Fast

Chickahominy Pipeline project tries to exploit an apparent regulatory loophole

November 1, 2021

Local communities are skeptical of the Chickahominy Pipeline company, which plans to build a supply line through five Virginia counties. With no track record and very little experience in pipeline construction, the company's capacity to take on this project is questionable.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/10/Chickahominy-feature.jpg 667 1500 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-11-01 13:29:122021-12-17 11:53:41Chickahominy Pipeline project tries to exploit an apparent regulatory loophole



Map Update on Criminal Charges Facing Mariner East 2 Pipeline

October 29, 2021
/

2 Comments

FracTracker mapped the 21 locations and over 120 violations by Energy Transfer Partner since Mariner East 2 Pipeline construction began.

Read more

https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/10/Mariner-East-2-feature.jpg 667 1500 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2021-10-29 13:02:432021-11-01 12:17:20Map Update on Criminal Charges Facing Mariner East 2 Pipeline

It’s Time to Stop Urban Oil Drilling in Los Angeles

September 14, 2021

Oil & gas wells in Los Angeles disproportionately impact marginalized communities, producing dangerous levels of invisible, toxic emissions.

Read more

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Infrastructure Networks in Texas

September 14, 2021

This map illustrates infrastructure networks in Texas and explores how these unseen webs connect us and improve lives, but also carry risks and burdens.
Read more
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California Prisons are Within 2,500’ of Oil and Gas Extraction

September 9, 2021

California prisoners are on the frontlines of the environmental justice movement, thousands living within 2,500’ of operational O&G wells.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/09/National-Prison-Strike-poster-feature.jpg 667 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-09-09 08:00:082021-09-08 17:30:46California Prisons are Within 2,500’ of Oil and Gas Extraction

New power plant proposal called senseless and wasteful by climate groups

August 26, 2021

Residents and local advocacy groups are fighting a new power plant in Renovo, PA, planned to be constructed on an abandoned rail yard.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/08/kemap.jpg 400 900 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-08-26 11:19:442021-08-26 15:08:04New power plant proposal called senseless and wasteful by climate groups

Ongoing Safety Concerns over Shell's Falcon Pipeline

August 24, 2021

Ohio River Valley Groups react to a new safety warning issued by federal regulators to Shell regarding the troubled Falcon Pipeline
Read more

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New Neighborhood Drilling Permits Issued While California Fails to Act on Public Health Rules

August 5, 2021

California drilling permits continue while Frontline communities and grassroots groups call for an immediate moratorium and 2,500' setback.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/08/BLenker_infrastructure-oilrig-southLA-CA_Oct2017-feature.jpg 667 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-08-05 16:38:392021-08-05 16:38:39New Neighborhood Drilling Permits Issued While California Fails to Act on Public Health Rules

The world is watching as bitcoin battle brews in the US

August 2, 2021
/

15 Comments
If Gov. Cuomo wants to lead the nation on climate, he has to address the impacts of proof of work cryptocurrency mining industry in New York.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/08/Bitcoin-feature.jpg 667 1500 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-08-02 17:05:372022-01-04 10:48:28The world is watching as bitcoin battle brews in the US

Lycoming Watershed Digital Atlas

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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/07/Lycoming-feature.jpg 667 1500 FracTracker Alliance https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png FracTracker Alliance2021-07-27 09:58:142021-07-28 11:23:19Lycoming Watershed Digital Atlas

California Oil & Gas Drilling Permits Drop in Response to Decreased Permit Applications to CalGEM

July 26, 2021

As California permit approvals for new oil & gas well drills decrease, Consumer Watchdog urges the Governor to move from fossil fuels.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/07/California-oil-drilling-feature.jpg 400 900 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-07-26 13:56:312021-07-26 14:03:09California Oil & Gas Drilling Permits Drop in Response to Decreased Permit Applications to CalGEM

California Denies Well Stimulation Permits

July 20, 2021

California regulators recently denied 21 well stimulation permit applications—a welcomed move in the right direction—but not enough.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/07/California-oil-fields-feature.jpg 667 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-07-20 16:32:222021-07-20 17:36:11California Denies Well Stimulation Permits

Mapping PFAS “Forever Chemicals” in Oil & Gas Operations

July 15, 2021
/

2 Comments
FracTracker Alliance released a new map identifying the locations of over 1,200 oil and gas wells using toxic “forever chemicals” in Arkansas, Louisiana, Oklahoma, New Mexico, Texas, and Wyoming.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/07/PSR-PFAS-feature.jpg 667 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2021-07-15 07:55:282021-07-15 07:55:28Mapping PFAS “Forever Chemicals” in Oil & Gas Operations

Updated National Energy and Petrochemical Map

June 30, 2021
/

1 Comment

We first released this map in February of 2020. In the year since, the world's energy systems have experienced record changes. Explore the interactive map, updated by FracTracker Alliance in April, 2021.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/06/National-Map-2021-Feature.jpg 667 1500 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2021-06-30 08:00:252022-05-02 15:24:21Updated National Energy and Petrochemical Map

Ohio, West Virginia, Pennsylvania Fracking Story Map

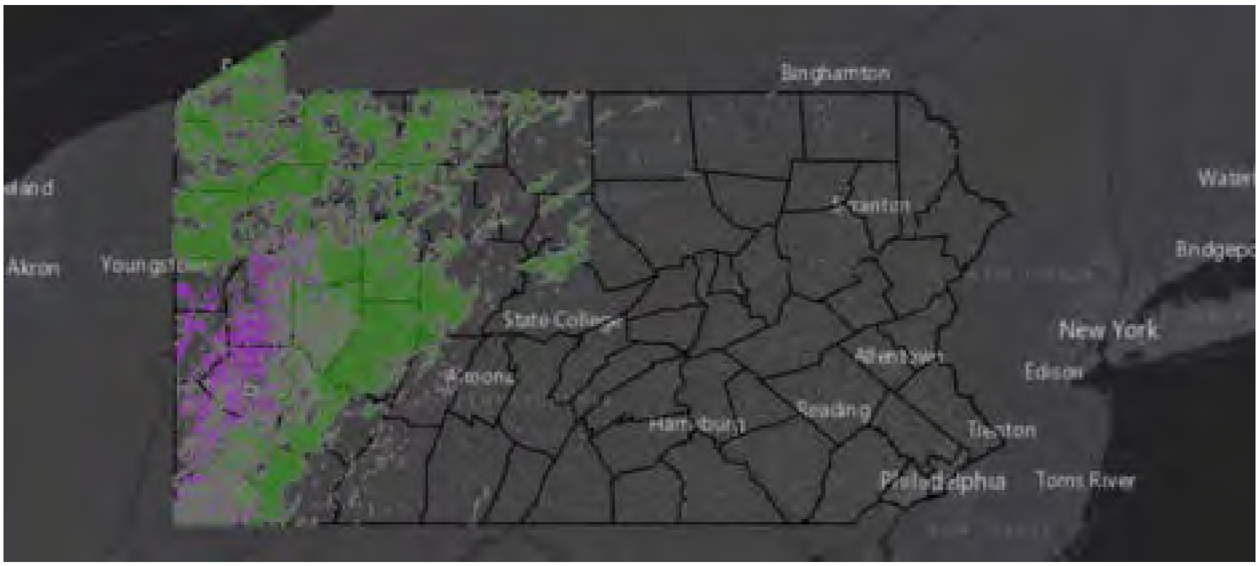
June 11, 2021

FracTracker's aerial survey of unconventional oil & gas infrastructure and activities in northeast PA to southern OH and central WV
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/06/TAuch_Infrastructure-Hopedale_Cryogenic_Plant-MarkWest_Energy-HarrisonCounty-OH_Nov2020-Feature.jpg 667 1500 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2021-06-11 12:26:292021-07-01 11:12:42Ohio, West Virginia, Pennsylvania Fracking Story Map

Ohio & Fracking Waste: The Case for Better Waste Management

June 3, 2021

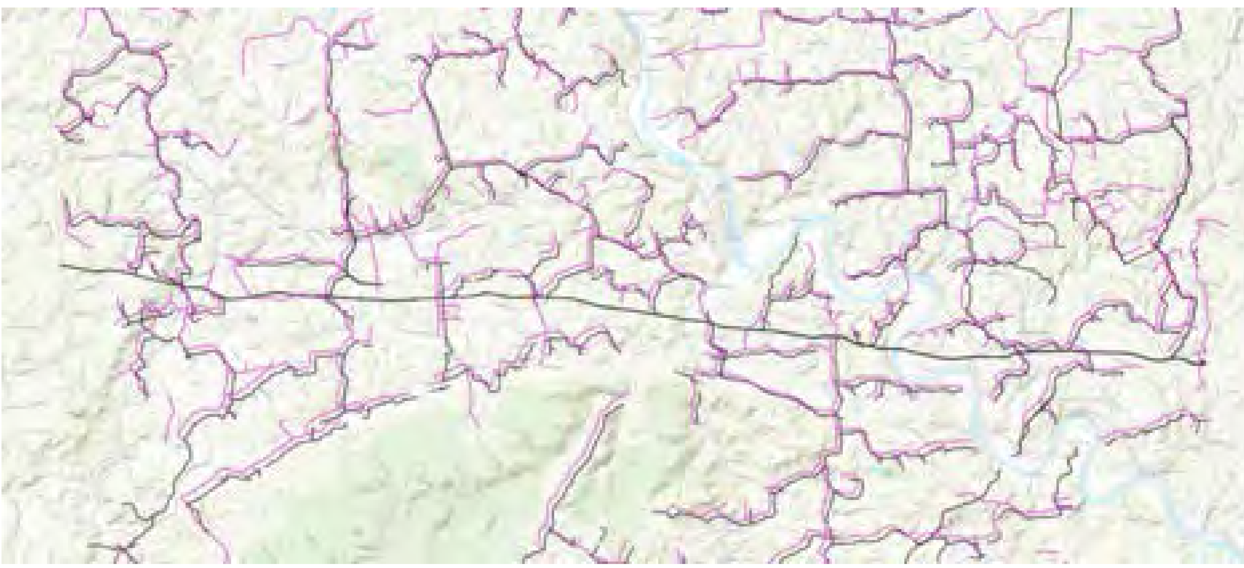
Insights on Ohio’s massive fracking waste gap, Class II injection well activity, and fracking waste related legislation
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/06/Myers-ClassII-InjectionWell-Stallion-SWD-VikingResources-PortageCounty-OH_March2021-feature.jpg 667 1500 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2021-06-03 12:51:592021-06-11 14:02:03Ohio & Fracking Waste: The Case for Better Waste Management



https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/05/Pennsylvania-conventional-wells-feature.jpg 667 1500 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2021-05-27 17:57:282021-05-28 09:53:57Pennsylvania Conventional Well Map Update

EPA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/05/Colonial-pipeline-spill-feature.jpg 667 1500 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-05-26 07:00:272023-07-18 10:31:34Impacts of 2020 Colonial Pipeline Rupture Continue to Grow

Jared Durelle https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/05/Stop-Alton-Gas-Treaty-Truckhouse-feature-photo-by-Jared-Durelle.jpg 667 1500 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-05-20 14:50:522022-01-10 17:07:38Gas Storage Plan vs. Indigenous Rights in Nova Scotia



https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/05/Bradford-County-PA-gathering-lines-feature.jpg 667 1500 Intern FracTracker https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Intern FracTracker2021-05-19 10:51:122021-05-20 14:41:22Mapping Gathering Lines in Bradford County, Pennsylvania

Trends in fracking waste coming to New York State from Pennsylvania

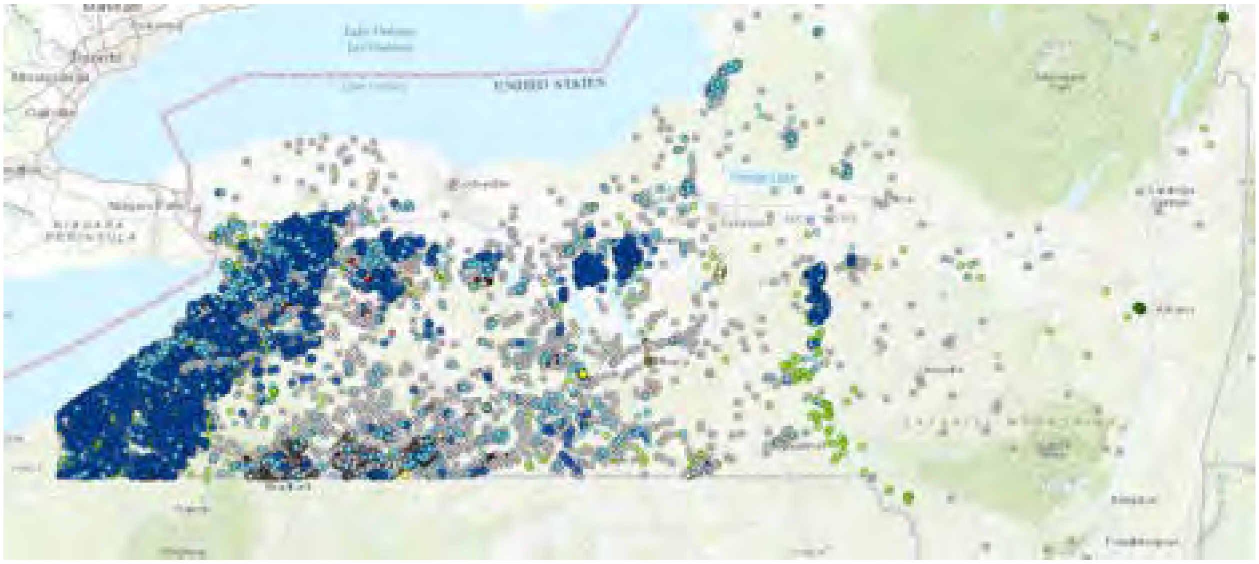
April 20, 2021
/

2 Comments
Over the past decade, New York State has seen a steep decline in the quantity of waste products from the fracking industry sent to its landfills for disposal. Explore FracTracker's 2020 updated data.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/PA-Unconventional-Drilling-Waste-Disposal-in-NYS-2011-20-feature-scaled.jpg 667 1500 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-04-20 14:05:162021-05-19 10:54:04Trends in fracking waste coming to New York State from Pennsylvania

2021 Pipeline Incidents Update: Safety Record Not Improving

April 14, 2021

The map below shows 6,950 total incidents since 2010, translating to 1.7 incidents per day. Pipelines are dangerous, in part because regulation around them is ineffective.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/49770601811_6cc7e18996_k.jpg 716 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2021-04-14 15:01:522021-04-26 17:02:402021 Pipeline Incidents Update: Safety Record Not Improving



https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/New-York-State-wells-feature.jpg 833 1875 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-04-01 11:10:062021-04-15 14:08:35New York State Oil & Gas Well Drilling: Patterns Over Time

Risky Byhalia Connection Pipeline Threatens Tennessee & Mississippi Health, Water Supply

March 17, 2021
/

2 Comments
The proposed Byhalia Connection pipeline project is situated in a particularly problematic intersection where environmental justice, hydrology, geology, and risks to human and environmental health intersect.

Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/03/Byhalia-map-feature-2-scaled.jpg 667 1500 Karen Edelstein https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Karen Edelstein2021-03-17 17:06:302021-09-16 13:15:25Risky Byhalia Connection Pipeline Threatens Tennessee & Mississippi Health, Water Supply

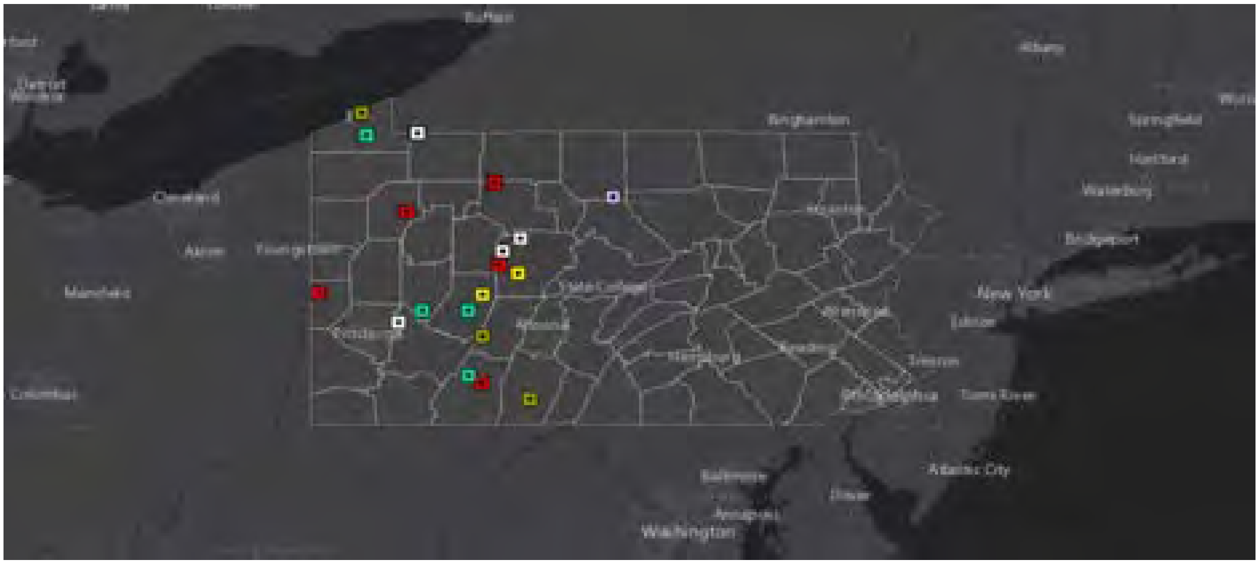
Shell’s Falcon Pipeline Under Investigation for Serious Public Safety Threats

March 17, 2021

Shell’s Falcon Pipeline, which is designed to carry ethane to the Shell ethane cracker in Beaver County, PA for plastic production, has been under investigation by federal and state agencies, since 2019.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/03/Falcon-Ohio-River-Crossing-Feature-A.LauschkeLightHawk-scaled.jpg 667 1500 Erica Jackson https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Erica Jackson2021-03-17 08:48:432021-04-15 15:11:21Shell’s Falcon Pipeline Under Investigation for Serious Public Safety Threats

https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/03/Arvin-CA-well-sites-and-schools-feature-scaled.jpg 667

1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-03-04 15:29:422021-04-15 15:14:45Kern County's Drafted EIR Will Increase the Burden for Frontline Communities

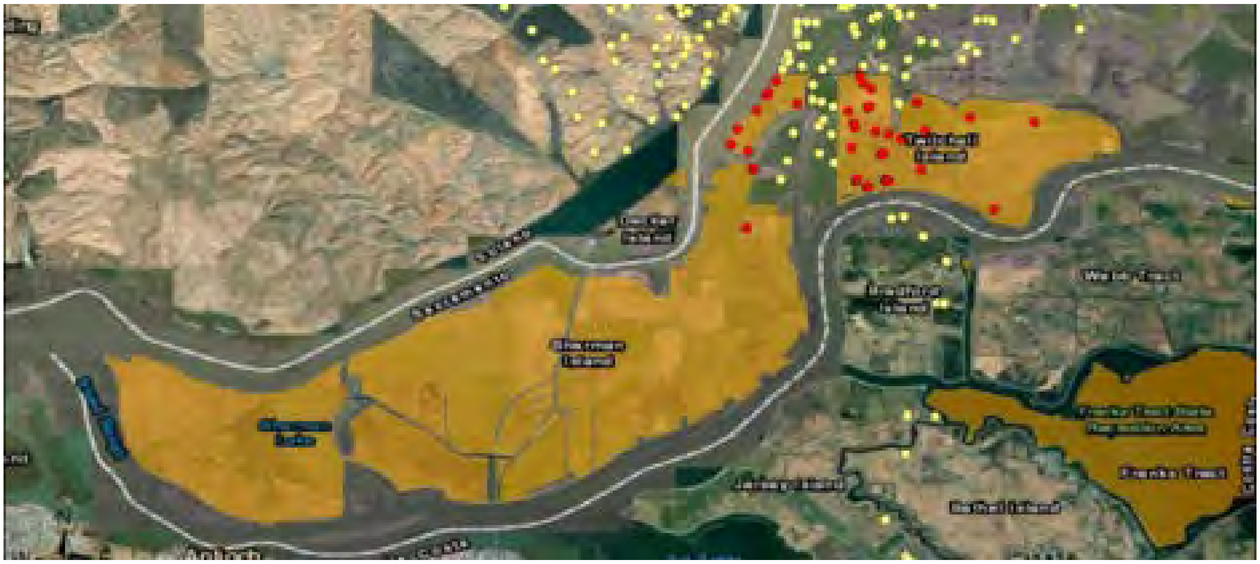


FracTracker Alliance, 2021 https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/02/Waste-Disposal-Wells-in-Pennsylvania-feature-scaled.jpg 667 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2021-02-26 12:23:392021-04-15 14:08:41Pennsylvania's Waste Disposal Wells – A Tale of Two Datasets

California Oil & Gas Setbacks Recommendations Memo

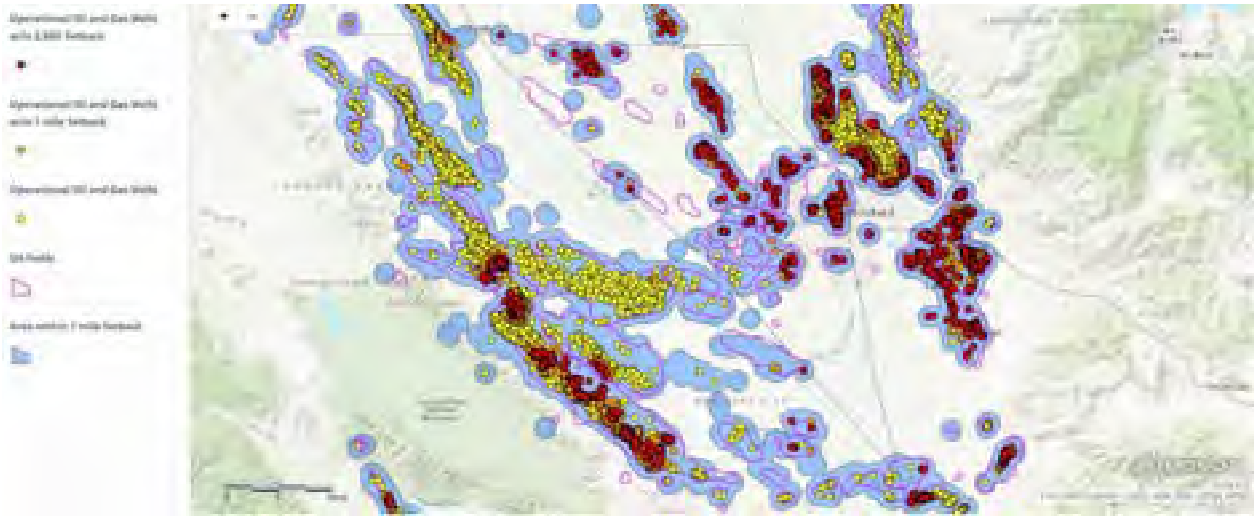
February 23, 2021

The purpose of this memo is to recommend guidelines to CalGEM for evaluating the economic value of the social benefits and costs to people and the environment in requiring a 2,500 foot setback for oil and gas drilling (OGD) activities.
Read more
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/02/Los-Angeles-skyline-feature-scaled.jpg 667 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-02-23 14:42:162021-04-15 14:08:42California Oil & Gas Setbacks Recommendations Memo



https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/02/Figure-2.-There-are-50-operational-oil-and-gas-wells-permitted-on-California-state-lands-in-the-Sacramento-River-Delta-feature-scaled.jpg 667 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2021-02-12 17:42:002021-04-15 14:08:43Oil and Gas Wells on California State Lands

https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/03/Control-your-dust-frac-sand-feature-scaled.jpg 667 1500 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2021-01-29 10:30:092021-04-15 14:08:43Industrial Impacts in Michigan: A Photo Essay & Story Map



https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2020/12/CASetbacksMappic.jpg 614 1500 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2020-12-17 13:45:242021-04-15 14:16:02People and Production: Reducing Risk in California Extraction

https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2019/08/EQT-Tioga-Wide-7.gif 300 800 Kyle Ferrar, MPH https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Kyle Ferrar, MPH2020-11-18 12:40:132021-04-15 14:16:04Documenting emissions from new oil and gas wells in California

https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2020/10/TAuch_infrastructure-wellpad-sandtruck-ChesapeakeAppalachia-RainSulWellpad-SullivanCounty-PA_July2020-feature-scaled.jpg 667 1500 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2020-10-15 11:24:272021-04-15 14:16:07Energy Security, International Investment, and Democracy in the US Shale Oil & Gas Industry

https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2020/08/FracTracker-in-the-Field-promotion5-scaled.jpg 844 1500 FracTracker Alliance https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png FracTracker Alliance2020-08-14 12:44:552021-04-15 14:16:11FracTracker in the Field: Building a Live Virtual Map

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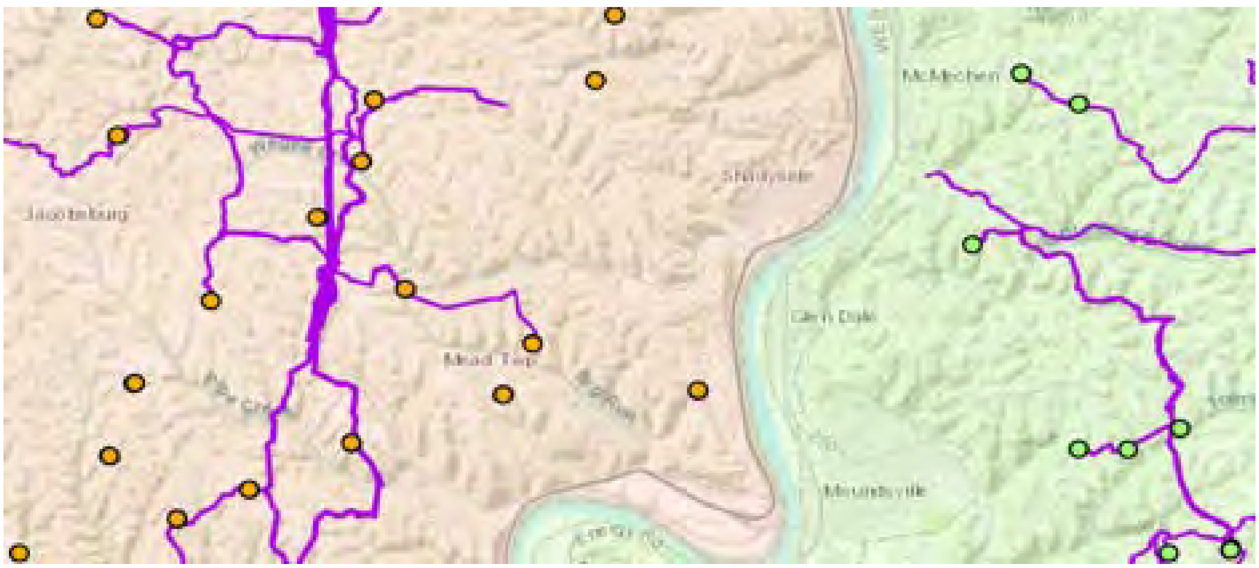

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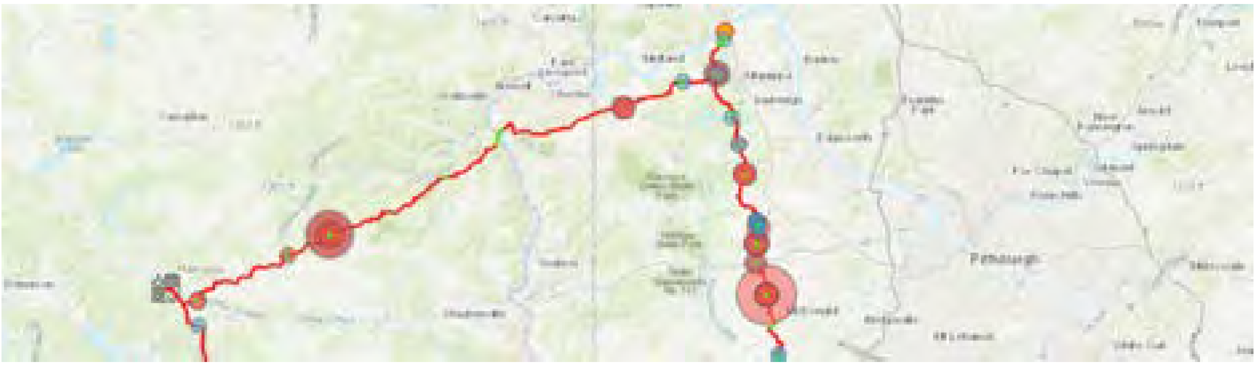

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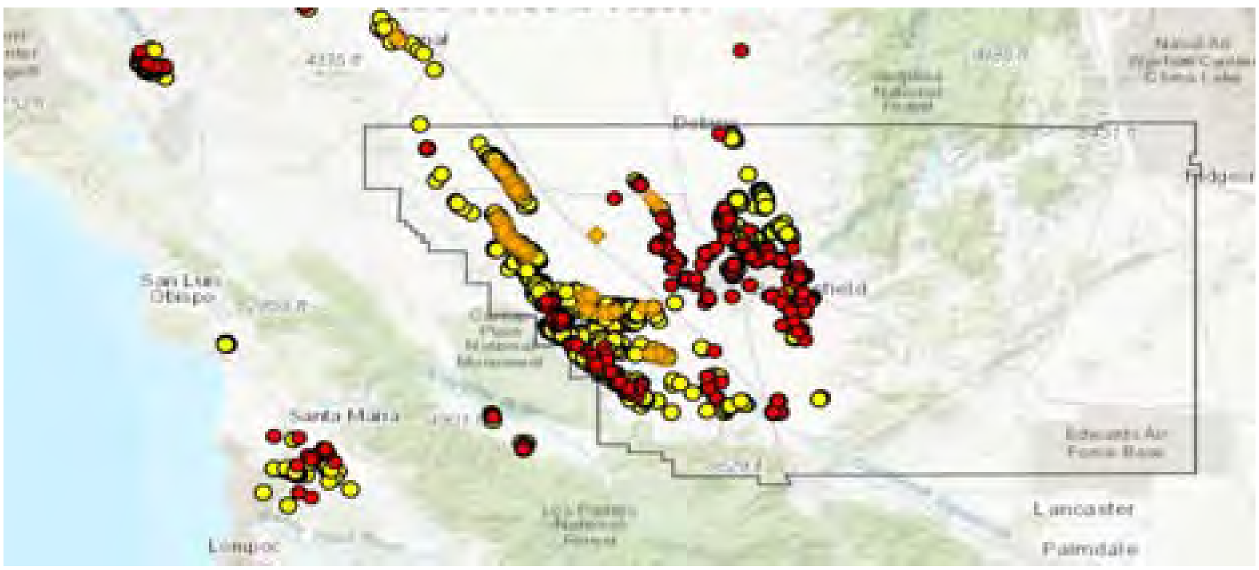

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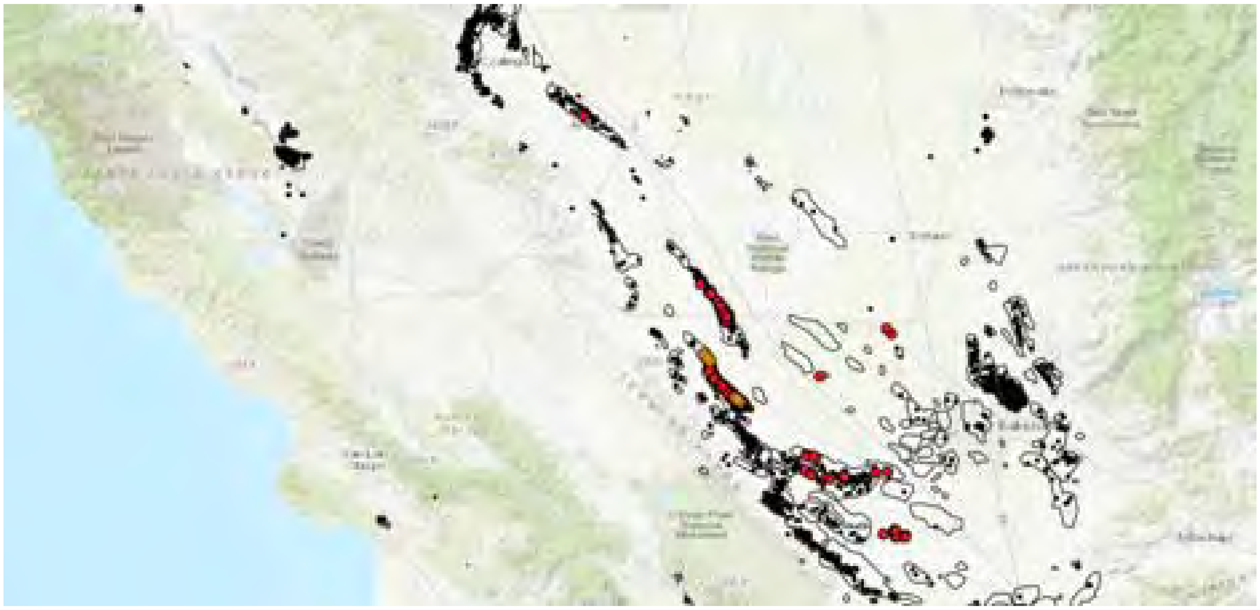

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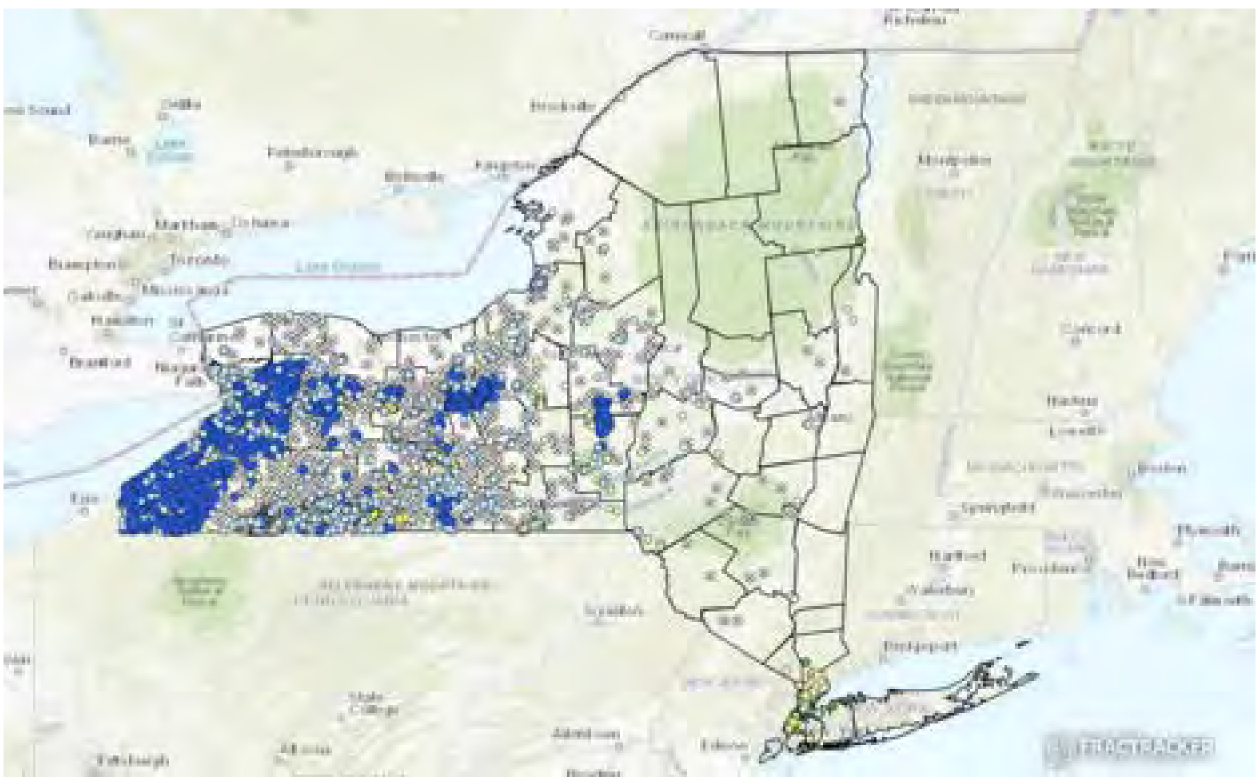

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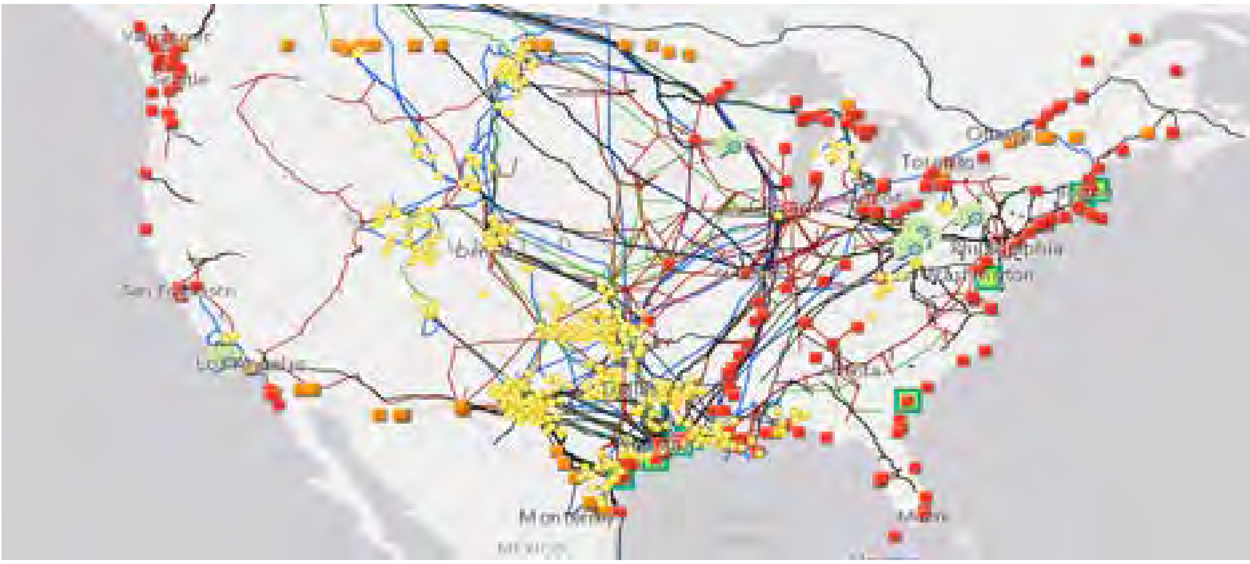

National Energy and Petrochemical Map

February 28, 2020
/

1 Comment
This map from FracTracker Alliance is filled with energy and petrochemical data. Explore the map, continue reading to learn more, and see how your state measures up!
Read more
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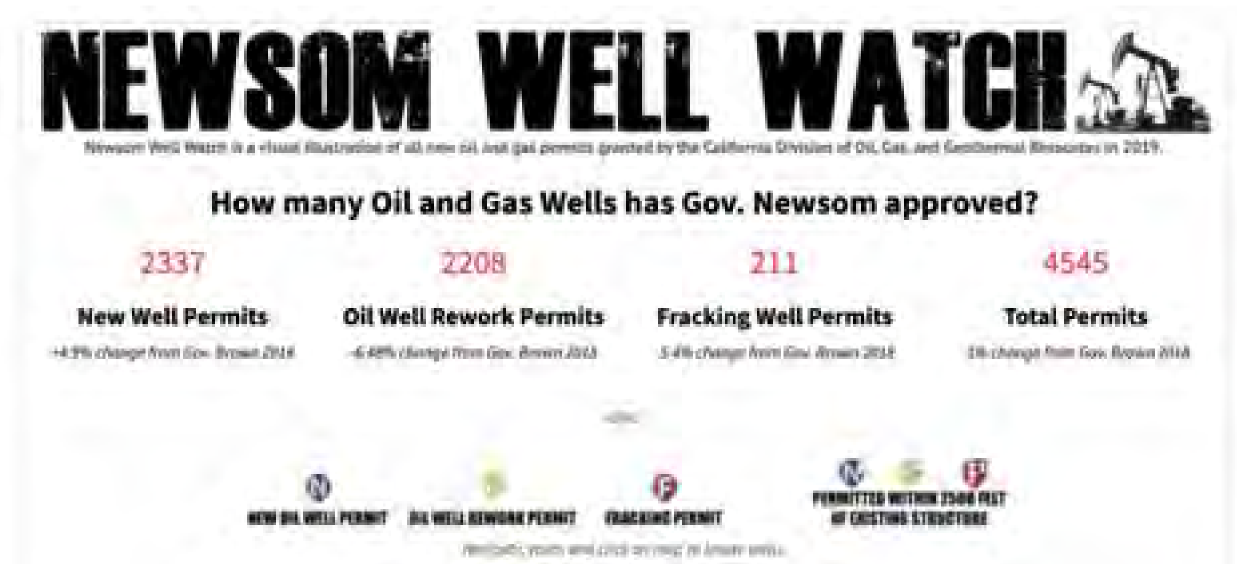

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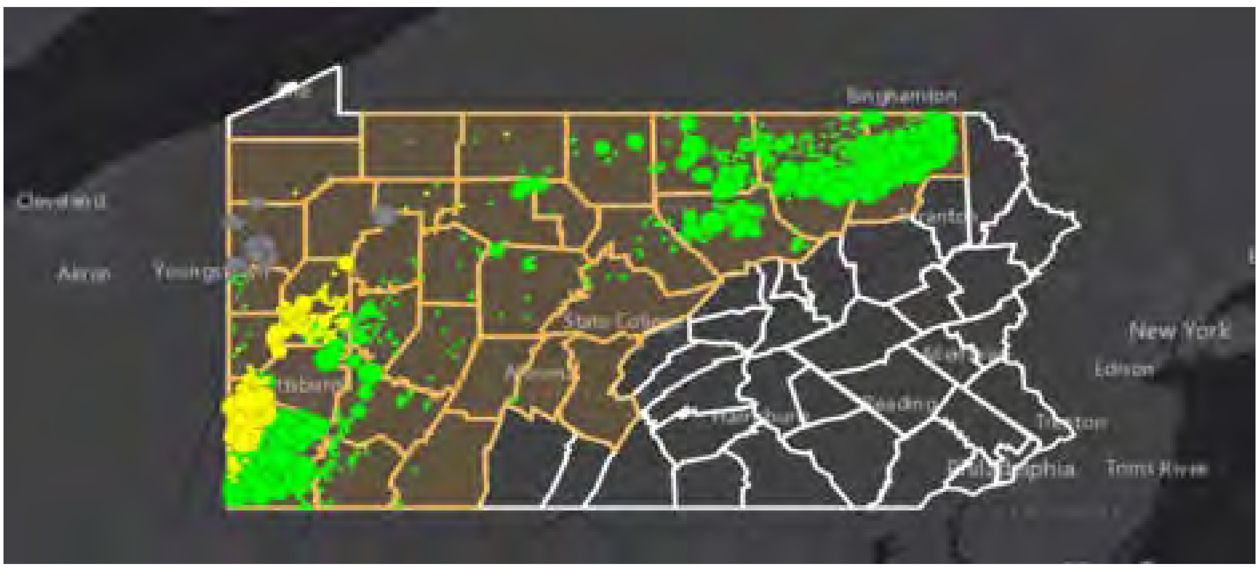

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How State Regulations Hold Us back and What Other Countries are doing about Fracking

October 10, 2019
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3 Comments
While it might be tempting to welcome an industry that often creates a temporary economic spike, the costs of mitigating the environmental damage from fracking far out-weighs the profit gained.
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Ohio's Secret Fracking Chemicals

Records Show Widespread Use of Secret Fracking Chemicals Poses Risks to Water Supplies, Health in the Buckeye State

Research Report

Dusty Horwitt, J.D.
Partnership for Policy Integrity
September 16, 2019

PFPI
driven by data

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Abandoned Wells in Pennsylvania: We’re Not Doing Enough

August 8, 2019

Pennsylvania does not have adequate plan to address thousands of dangerous abandoned natural gas and oil wells within the state. FracTracker intern Isabelle Weber gives recommendations to address this widespread issue.
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Smith https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Shannon Smith2019-08-07 09:36:032020-03-20 17:32:33Wildness Lost – Pine Creek

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https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2019/06/Washington-County-Rig-2-scaled.jpg 667 1500 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2019-06-10 12:07:422021-04-15 14:56:30Production and Location Trends in PA: A Moving Target

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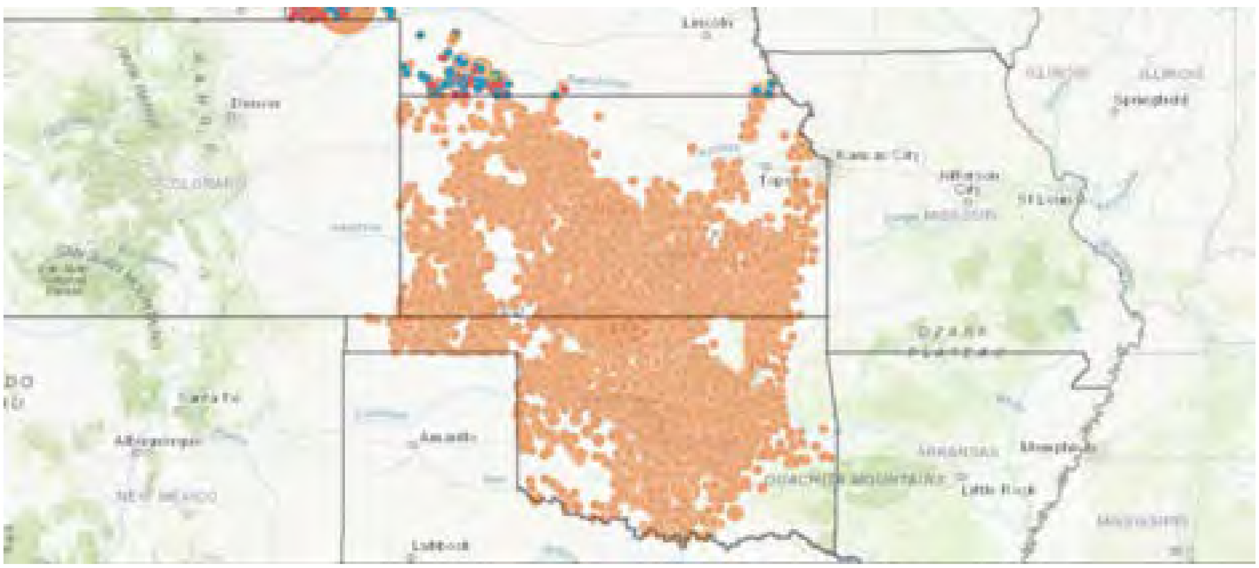

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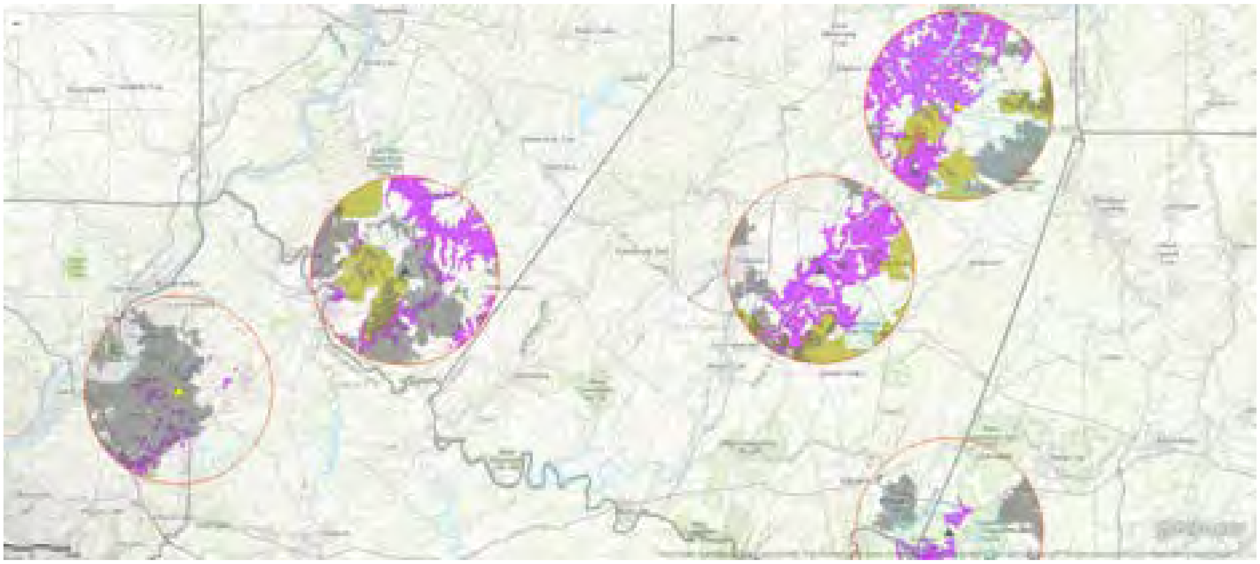

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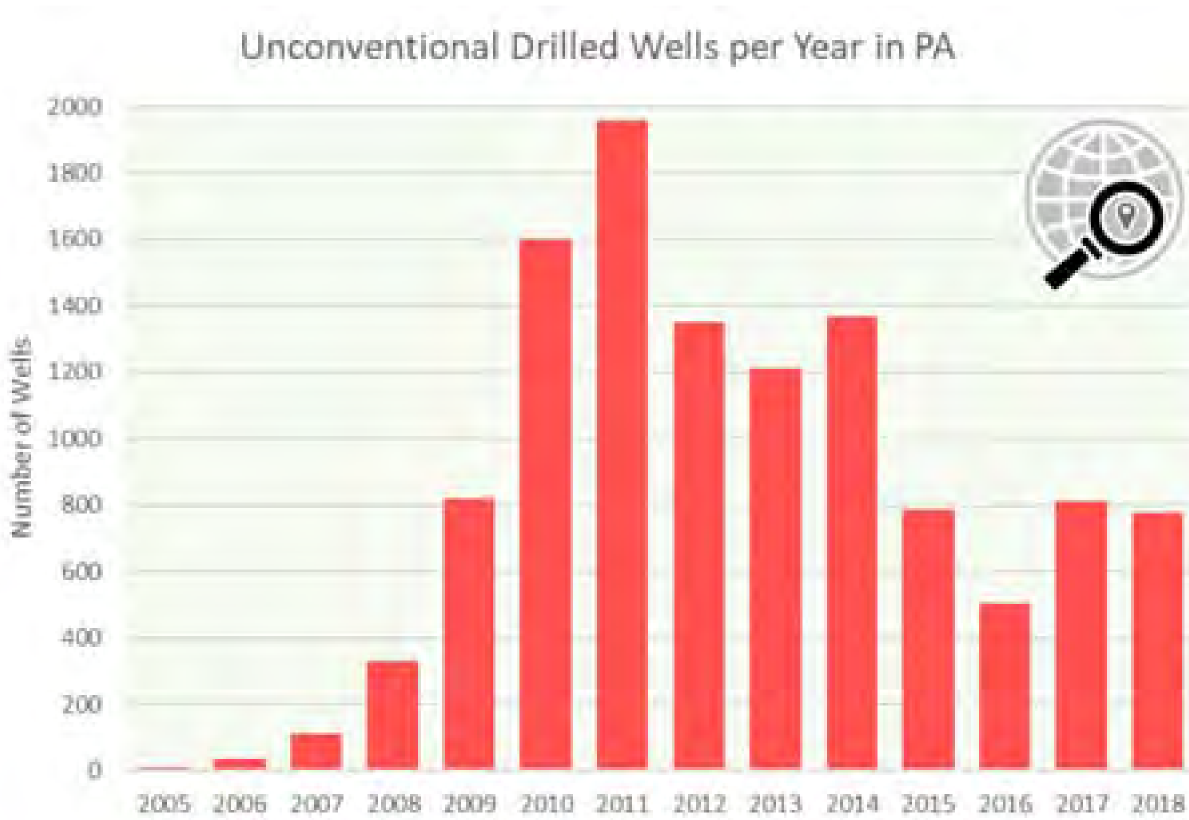
https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2019/01/InjectionWell-Sky-Feature.jpg 400 900 Ted Auch, PhD https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Ted Auch, PhD2019-01-09 14:37:272021-04-15 14:56:57A Disturbing Tale of Diminishing Returns in Ohio



https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2019/01/UncWellsPerYear_2005_2018.png 806 1218 Matt Kelso, BA https://www.fractracker.org/a5ej20sjfwe/wp-content/uploads/2021/04/2021-FracTracker-logo-horizontal.png Matt Kelso, BA2019-01-08 14:14:382021-04-15 14:57:01Pennsylvania Drilling Trends in 2018

LITERALLY MILLIONS OF FAILING,

ABANDONED WELLS

March 29, 2019 / by Kyle Ferrar, MPH

By Kyle Ferrar [https://www.fractracker.org/author/kyleferrar/] , Western Program Coordinator, FracTracker Alliance

In California's Central Valley and along the South Coast, there are many communities littered with abandoned oil and gas wells, buried underground.

Many have had homes, buildings, or public parks built over top of them. Some of them were never plugged, and many of those that were plugged have since failed and are leaking oil, natural gas, and toxic formation waters (water from the geologic layer being tapped for oil and gas). Yet this issue has been largely ignored. Oil and gas wells continue to be permitted without consideration for failing and failed plugged wells. When leaking wells are found, often nothing is done to fix the issue.

As a result, greenhouse gases escape into the atmosphere and present an explosion risk for homes built over top of them. Groundwater, including sources of drinking water, is known to be impacted by abandoned wells in California, yet resources are not being used to track groundwater contamination.

The term "abandoned" typically refers to wells that have been taken out of production. At the end of their lifetime, wells may be properly abandoned by operators such as Chevron and Shell or they may be orphaned.

When operators properly abandon wells, they plug them with cement to prevent oil, natural gas, and salty, toxic formation brine from escaping the geological formation that was tapped for production. Properly plugging a well helps prevent groundwater contamination and further air quality degradation from the well. The well-site at the surface may also be regraded to an ecological environment similar to its original state.

Wells that are improperly abandoned are either plugged incorrectly or are "orphaned" by their operators. When wells are orphaned, the financial liability for plugging the well and the environmental cleanup falls on the state, and therefore, the taxpayers.

You don't see them?

In California's Central Valley and South Coast abandoned wells are everywhere. Below churches, schools, homes, they even under the sidewalks in downtown Los Angeles!

FracTracker Alliance and Earthworks recently spent time in Los Angeles with an infrared camera that shows methane and volatile organic compound (VOC) emissions. We visited several active neighborhood drilling sites and filmed plumes of toxic and carcinogenic

VOCs floating over the walls ... rounding neighborhoods. We also visited sites where aband... plugged wells had failed.

In the video below, we are standing on Wilshire Blvd in LA's Miracle Mile District. An undocumented abandoned well under the sidewalk leaks toxic and carcinogenic VOCs through the cracks in the pavement as mothers push their children in walkers through the plume. This is just one case of many that the state is not able to address.

California regulatory data shows that there are 122,466 plugged wells in the state, as shown below in the map below. Determining how many of them are orphaned or improperly plugged is difficult, but we can come up with an estimate based on the wells' ages.

While there are no available d… re plugged, there are data on “spud dates,” the date when o…tors begin drilling into the ground. Of the 18,000 wells listing spud dates, about 70% were drilled prior to 1980. Wells drilled before 1980 have a higher risk of well casing failures and are more likely to be sources of groundwater contamination.

Additionally, wells plugged prior to 1953 are not considered effective [https://ieaghg.org/docs/wellbore/webi05%20pres/T%20Benedictus,%20TNO.pdf] , even by industry standards. Prior to 1950, wells either were orphaned or plugged and abandoned with very little cement. Plugging was focused on protecting the oil reservoirs from rain infiltration rather than to “confine oil, gas and water in the strata in which they are found and prevent them from escaping into other strata [https://oilandgas.uslegal.com/state-oil-and-gas-laws/texas/] .” Of the wells with drilling dates in the regulatory data, 30% are listed as having been drilled prior to the use of cement in well plugging.

With a total of over 245,000 wells in the state database, and considering the lack of monitoring prior to 1950, it’s reasonable to assume there are over 80,000 improperly plugged and unplugged wells in California.

MAP OF CALIFORNIA’S PLUGGED WELLS

CA Oil and Gas Fields

CA Plugged Wells

CA Counties

View map fullscreen [https://maps.fractracker.org/latest/?appid=14d74e091f7047369c78c9ba3732bc00] | How FracTracker maps work [https://www.fractracker.org/resources/how-fractracker-works/]

The regions with the highest counts of plugged wells are the Central Valley and the South Coast. The top 10 county ranks are listed below in Table 1. Kern County has more than half of the total plugged wells in the entire state.

TABLE 1. RAN[illegible] COUNTIES BY PLUGGED WELL COUNTS

Rank	County	Plugged Well Count
1	Kern	65,733
2	Los Angeles	17,139
3	Orange	7,259
4	Fresno	6,970
5	Ventura	4,302
6	Santa Barbara	4,192
7	Monterey	2,266
8	San Luis Obispo	1,463
9	Solano	1,456
10	Yolo	1,383

The issue is not unique to California. Nationally, an estimated 2.56 million oil and gas wells have been drilled and 1.93 million [https://www.epa.gov/sites/production/files/2017-06/documents/6.22.17_ghgi_stakeholder_workshop_2018_ghgi_revision_-

_abandoned_wells.pdf] wells [illegible] Using interpolated data, the EPA estimates that as of 201[illegible] were 3.12 million abandoned wells in the U.S. and 69% of them were left unplugged.

In 2017, FracTracker Alliance organized an exercise to track down the locations of Pennsylvania's abandoned wells that are not included in the PA Department of Environmental Protection's digital records. Using paper maps and the FracTracker Mobile App [https://www.fractracker.org/apps/] , volunteers explored Pennsylvania woodlands in search of these hidden greenhouse gas emitters.

What are the risks?

EMISSIONS

Studies by Kang et al. 2014 [https://www.pnas.org/content/111/51/18173] , Kang et al 2016 [https://www.pnas.org/content/113/48/13636] , Boothroyd et al 2016 [https://www.sciencedirect.com/science/article/pii/S0048969715312535] , and Townsend-Small et al. 2016 [https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2015GL067623] have all measured methane emissions from abandoned wells. Both properly plugged and improperly abandoned wells have been shown to leak methane and other VOCs to the atmosphere as well as into the surrounding groundwater, soil, and surface waters. Leaks were shown to begin just 10 years after operators plugged the wells.

The high density of aging and improperly plugged wells is a major risk factor for the current and future development of California's oil and gas fields. When fields with old wells are reworked using new technology, such as hydraulic fracturing, CO2 flooding, or solvent flooding (including acidizing, water flooding, or steam flooding), the injection of additional fluid and gas increases pressure in a reservoir. [https://www.npc.org/Prudent_Development-Topic_Papers/2-25_Well_Plugging_and_Abandonment_Paper.pdf] Poorly plugged or aging wells often lack the integrity to avoid a blowout (the uncontrolled release of oil and/or gas from a well). There is a consistent risk that formation fluids will be forced to migrate up the plugged wellbores and bypass the existing plugs.

GROUNDWATER

In a 2014 report, the U.S. Geological Service [https://ca.water.usgs.gov/projects/oil-gas-groundwater/science/pathways/] warned the California State Water Resources Control Board that the integrity of abandoned wells is a serious threat to groundwater sources, stating, "Even a small percentage of compromised well bores could correspond to a large number of transport pathways."

The California Council on Science and Technology (CCST) has also suggested the need for additional research on existing aquifer contamination. In 2014, they called for widespread testing [https://ccst.us/reports/achieving-a-sustainable-california-water-future-through-innovations-in-science-and-technology/] of groundwater near oil and gas fields, which has still not occurred.

surface. In many cases, such as in Pennsylvania, Texas, and California, where drilling began prior to the turn of the 20th century, many wells have been left unplugged. Of the abandoned wells that were plugged, the plugging process was much less adequate than it is today.

If plugged wells are allowed to leak, surface expressions can form. These leaks can travel to the Earth's crust where oil, gas, and formation waters saturate the topsoil. A construction supervisor for Chevron named David Taylor was killed [https://www.latimes.com/local/california/la-me-oil-steam-20151129-story.html] by such an event in the Midway-Sunset oil field near Bakersfield, CA. According to the LA Times, Chevron had been trying to control the pressure at the well-site. The company had stopped injections near the well, but neighboring operators continued high-pressure injections into the pool. As a result, migration pathways along old wells allowed formation fluids to saturate the Earth just under the well-site. Tragically, Taylor fell into a 10-foot diameter crater of 190° fluid and hydrogen sulfide.

California regulations

Following David Taylor's death in 2011, California regulators vowed to make urgent reforms to the management of underground injection, and new rules finally went into effect on April 1, 2018. These regulations require more consistent monitoring of pressure and set maximum pressure ... help with the management of enhanced oil recovery opera..., such as steam and water flooding and wastewater disposal, the issue of abandoned wells is not being addressed.

New requirements incentivizing operators to plug and abandon idle wells [https://www.californiaenvironmentallawblog.com/oil-and-gas/doggr-issues-revised-regulations-for-uic-and-idle-wells/] will help to reduce the number of orphan wells left to the state, but nothing has been done or is proposed to manage the risk of existing orphaned wells.

Conclusion

Why would the state of California allow new oil and gas drilling when the industry refuses to address the existing messes? Why are these messes the responsibility of private landholders and the state when operators declare bankruptcy?

New bonding rules in some states have incentivized larger operators to plug their own wells, but old low-producing or idle wells are often sold off to smaller operators or shell (not Shell [https://www.shell.com/]) companies prior to plugging. This practice has been the main source of orphaned wells. And regardless of whether wells are plugged or not, research shows that even plugged wells release fugitive emissions that increase with the age of the plug.

If the fossil fuel industry we[illegible] million currently active wells, [https://www.fractracker.org/[illegible]/08/1[illegible] million wells/] there would be nearly 5 million plugged wells that require regular inspections, maintenance, and for the majority, re-plugging, to prevent the flow of greenhouse gases. This is already unattainable, and drilling more wells adds to this climate disaster.

By Kyle Ferrar [https://www.fractracker.org/author/kyleferrar/] , Western Program Coordinator, FracTracker Alliance

SHARE THIS ENTRY

8

REPLIES

Clinton Rhodd

August 21, 2020 at 8:19 pm

I been the petroleum industry for [illegible] Years. In 80s I been telling [illegible] the that the wells are not being plugged right. They would come back and say we [illegible]ng the wells are to State, BLM and the RRC specifications I told they are wrong. I even told DEQ they told they would look in to it. They said they would let me know. I never heard a word around then. They just kicked ball down the road. Clint Rhodd Lusk, Wyoming.

Erica Jackson
August 24, 2020 at 2:31 pm

Hi Clinton – thanks for sounding the alarm around this issue and sharing your perspective. If you'd like to talk more about your experience and how well-plugging could be improved feel free to email us at info@fractracker.org

---

Horace Moning
August 21, 2020 at 10:26 am

How do you get more information on these wells

Erica Jackson
August 24, 2020 at 2:35 pm

Hi Horace – Unfortunately, there is a real lack of information about these wells from public agencies. However, for the wells on the map, you can click on them and a pop up box will appear with more details. If you have questions about those details let us know. Is there any specific type of info that you're looking for? Feel free to email us at info@fractracker.org if that's easier.

Clinton Rhodd

My name in Clinton Rhodd

I have been the drilling business fo[illegible]0 years as a drilling consultant for. Major and independent oil and gas companies. I have been telling them the they have not been plugging the wells properly. They tell me this is what the State and BLM engineers calls for. The best cement will deteriorate. In 30 years and oil and gas well work up in the water aquifer in 30 years. They still dont listen. Text me at 307-567-3110

Skylar Williams

December 16, 2019 at 12:31 pm

I had no idea that leaks from abandoned wells could lead to a pathway being made for methane and fluids to escape to Earth's surface. My brother just bought a ranch and there's an abandoned well on the property. I'll recommend that he call a professional to come and take a look before anything happens.

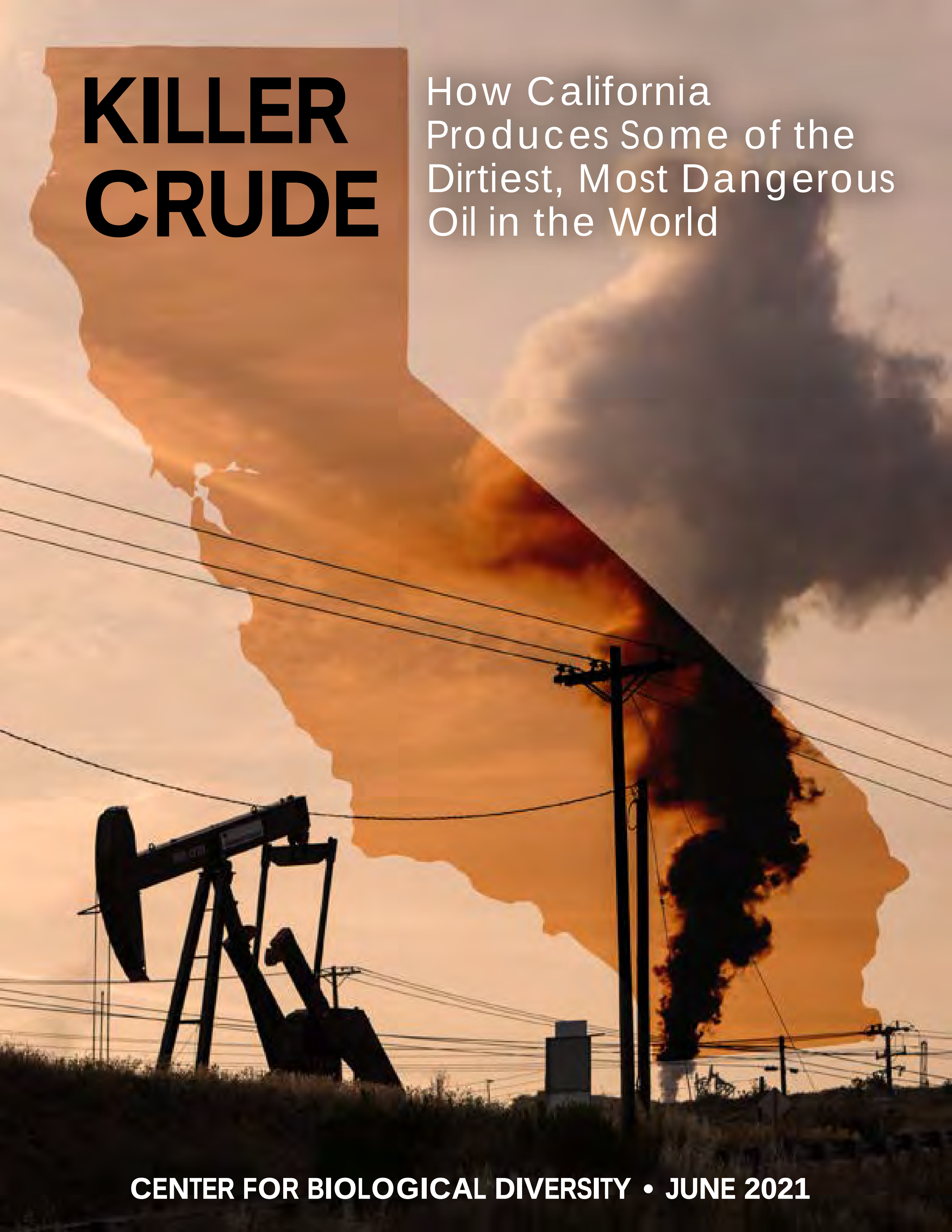
Derek McDoogle

July 31, 2019 at 9:50 am

I did not know the fact that when leaking wells are found, often nothing is done to fix the issue. I've heard that in some states, there are a lot of wells that have been abandoned. Thanks for the information about how properly plugging a well help prevent groundwater contamination.

> **Erica Jackson**
>
> July 31, 2019 at 1:06 pm
>
> Glad you found it helpful- Abandoned and orphaned wells are a growing problem in many states- In Pennsylvania, according to the state's Department of Environmental Protection, 300,000 to 760,000 wells have been drilled since 1859, and somewhere between 100,000 and 560,000 oil and gas wells are unaccounted for still today!

Comments are closed.



KILLER CRUDE

How California Produces Some of the Dirtiest, Most Dangerous Oil in the World

CENTER FOR BIOLOGICAL DIVERSITY • JUNE 2021

KILLER CRUDE: HOW CALIFORNIA PRODUCES SOME OF THE DIRTIEST, MOST DANGEROUS OIL IN THE WORLD

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Cover photo by Drew Bird Photography

JUNE 2021

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Executive Summary

Despite California's reputation as a global climate leader, California-sourced oils are now among the most climate-damaging in the world and are rapidly becoming even more so. This report analyzes the state's oil production and refining to show the dramatic increase in California oil's carbon intensity over roughly the past decade. It finds that California-sourced oils have gone from bad to worse and are now dirtier than oils refined here from other states and global regions including the Middle East, South America, Africa, Canada and Mexico.

California has a huge impact as the nation's seventh-largest producer of crude oil and the third-largest oil refiner. In 2020 California oil companies produced more than 144 million barrels of crude oil, and state regulators issued more than 1,900 permits for new oil wells. This takes our state in the wrong direction at a critical juncture, as the scientific consensus tells us that we must phase out fossil fuel extraction to keep global heating below 1.5 degrees Celsius and prevent climate catastrophe.

Our findings on the worsening carbon intensity of California oil give state leaders an even greater opportunity — and responsibility — to confront ongoing health harms, climate damage and environmental racism by ending new oil and gas approvals and immediately banning fracking in the state. In April 2021 Gov. Gavin Newsom ordered state regulators to ban fracking by 2024 and study the phaseout of California oil production by 2045, but the climate and health crises demand action now, not decades in the future.

We studied upstream carbon intensity values (from exploration to refinery gate) provided by the California Air Resources Board for all oils refined in California. We found that the average carbon intensity of all oil refined in California is increasing, but the average carbon intensity of just the oil produced in California is increasing far faster. The carbon intensity of California-sourced oil is growing at twice the rate of all oils refined in California, and nearly three times the rate of oils produced outside of California (Figure E1). By 2019 the average carbon intensity of California-sourced crudes was more than one-and-a-half times greater than that of crudes produced outside of California.

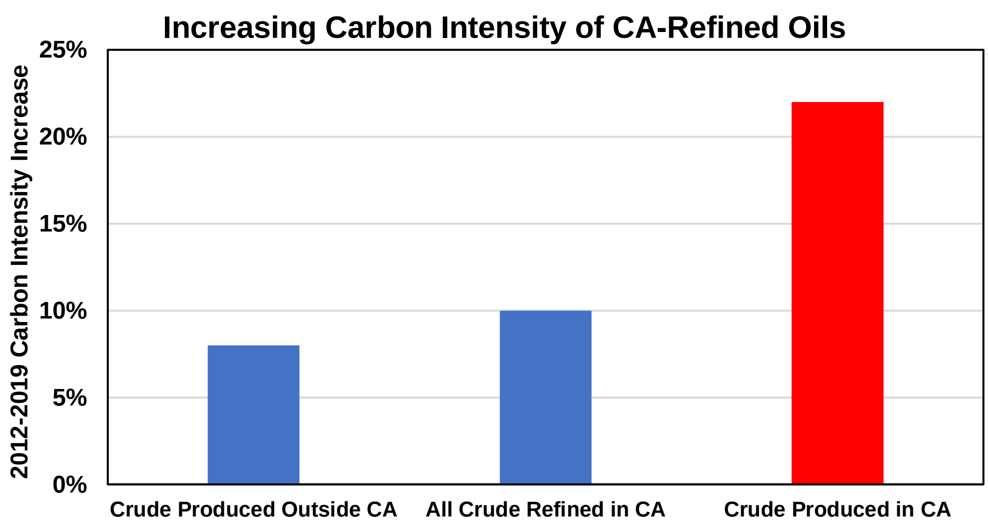

Figure E1: Increase in average carbon intensity between 2012 and 2019 for: (1) crude produced outside CA; (2) all crude refined in CA; (3) crude produced in CA.

Further evidence of California-sourced oil's outsized carbon footprint can be found in its contribution to the average carbon intensity of California-refined oil. California oil was 31% of all oil refined in California between 2012 and 2019 but was responsible for 39% of upstream carbon emissions.

Thus, on average, California oil emits more carbon dioxide per barrel than the rest of the global supply refined in California. So, although California oil production is declining, the increase in carbon intensity is helping to cancel out the climate benefits of declining production.

We also found that oil produced and refined in California is more climate-damaging than the notoriously dirty Canadian tar sands crude refined here. In 2019 the average upstream carbon intensity of California-sourced oil exceeded that of Canadian tar sands crude refined in California, with 98 kg CO_2eq/barrel for California oil and 90 kg CO_2eq/barrel for Canadian tar sands crude.

To avoid the worst dangers of climate change, the world must transition away from fossil fuels. No jurisdiction is better suited than California to lead the way in phasing out dirty oil and gas production. For California this means an end to approvals for new oil and gas wells and an immediate ban on fracking and related extreme techniques that only amplify the damage from extraction.

While a full phaseout of in-state production will take some time, it needs to be much faster than Gov. Newsom's 2045 target. A health-and-safety buffer should also be implemented immediately to prevent oil and gas drilling in communities and to protect public health and safety from air pollution and other harms of oil and gas extraction. Without taking these steps, California cannot protect the climate or the state's most vulnerable communities.

San Ardo Oil Field by Loco Steve/Flickr

Introduction: California's Oil Production Undermines Its Climate, Environmental Justice and Public Health Goals

Despite California's image as a leader on climate and the environment, the state's oil industry contributes heavily to dangerous climate-heating pollution. California is the nation's seventh-largest producer of crude oil and the third-largest oil refiner.[1] In 2020, California oil companies produced more than 144 million barrels of crude oil, while Gov. Newsom's state regulators issued more than 1,900 permits for new oil wells.[2] The flood of permits for new oil wells runs directly counter to the imperative to phase out fossil fuel extraction to prevent the worst climate damages. It also perpetuates the environmental justice and health crises caused by oil and gas extraction in California.

Overwhelming scientific consensus has shown that without deep and rapid emissions reductions, global warming will exceed 1.5 degrees Celsius compared to preindustrial levels, resulting in catastrophic damage around the world.[3] Every fraction of additional warming above 1.5 degrees will worsen these harms, threatening lives, livelihoods, the environment and global security for this and future generations. Because 75% of global greenhouse gas emissions and 85% of U.S. emissions come from fossil fuels,[4] phasing out fossil fuel extraction and combustion is of urgent necessity to avert climate catastrophe.

Unfortunately, today the world faces a fossil fuel "production gap" of tremendous proportions: Producers currently plan to extract far more fossil fuels than a livable planet will allow.[5] There is enough oil, gas and coal in already developed fields and mines globally — that is, places where the infrastructure is built and the capital is sunk — to far exceed the carbon budget for 1.5 degrees C if these reserves were all produced and burned.[6] This means that meeting global climate goals requires an immediate halt to the approval of new fossil fuel projects and a phaseout of existing oil, gas and coal extraction *before* the reserves in existing fields and mines are fully depleted.[7]

Nowhere in the world is better suited than California, with its wealthy, diverse economy and vibrant clean energy sector, to lead the way in a rapid phaseout of oil and gas extraction. To date, however, progress has been slow and insufficient. Gov. Newsom's order for regulators to study how to phase out oil extraction by 2045 could allow another two and a half decades of toxic inaction.

To make matters worse, much of the remaining oil in California's largest oilfields is heavy and carbon intensive.[8] The "heaviness" of an oil is defined by its API gravity, which is a measure of the oil's density. A crude oil is "light" if it has an API gravity of more than 31.1 degrees, "medium" if it has an API gravity from 22.3 to 31.1 degrees, "heavy" if it has an API gravity from 10 to 22.3 degrees and "extra heavy" if under 10 degrees. In 2018, 68% of California's crude oil production was heavy.[9] Heavy oils are especially climate-damaging because they often require energy-intensive techniques such as hydraulic fracturing, waterflood, steamflood and cyclic steam to extract. This greater energy demand results in greater greenhouse gas emissions as well as greater health and safety risks.

The heaviness of oil contributes to its carbon intensity, with heavier oils tending to be more carbon intensive. Carbon intensity is a value that estimates the emissions from the production, processing and transport of crude oil. Our study of carbon intensity values for oil refined in California, provided by the California Air Resources Board, shows that California-sourced oils are especially dirty in a global context and that their carbon intensity is rapidly increasing.

Oil and gas production in California has also caused an environmental justice and public health crisis in California. Eighteen percent of the state's population lives within a mile of at least one oil or gas well. [10] The highest-density oil and gas extraction areas are predominantly located near low-income communities and communities of color.[11] These communities are disproportionately exposed to the health harms associated with oil and gas extraction such as cancer,[12] respiratory illnesses[13] and pregnancy complications. Two recent studies focused on California specifically found associations between proximity to oil and gas production and preterm birth and low birth weight.[14] A recent Harvard study found that an estimated 34,000 Californians died prematurely in one year because of fossil fuel pollution.[15]

California's failure to rein in the dirty oil extraction within its own borders, using increasingly energy-intensive and dangerous techniques, completely undermines its climate, health and justice goals.

Study Description

California refines crude oil from countries around the world, including (as of 2019) Angola, Argentina, Brazil, Canada, Colombia, Ecuador, Equatorial Guinea, Ghana, Iraq, Kuwait, Mexico, Nigeria, Oman, Peru, Russia, Saudi Arabia, Trinidad and United Arab Emirates. California also refines oil from other U.S. states including Alaska, New Mexico, North Dakota, Texas and Utah, along with oil from federal offshore sources. The remaining oil refined in California comes primarily from its own 158 major oilfields.

California's 2019 oil production was only 27% of the total 600 million barrels refined in California.[16] In 2019, 13% of the oil refined in California was from other U.S. states, predominantly Alaska, New Mexico, North Dakota, Utah and Wyoming. Notably, the oils refined from these states were all light based on API gravity.[17] Similarly, oil refined in California from the Middle East (mainly Saudi Arabia, Iraq and Kuwait), constituting 26% of oil refined in California in 2019 and the dominant foreign source, was light.[18]

The only significant foreign source of heavy oil refined in California is South America (mainly Ecuador, Colombia and Brazil), constituting 22% of oil refined in 2019.[19] Oils from Canada and Mexico, including the infamous Canadian tar sands oils, are comparable in heaviness to California oils, but as less than 5% of the total oil refined in California in 2019, they are a relatively small source.[20]

For oil refined in California, the Oil Production Greenhouse gas Emissions Estimator (OPGEE) is the model used to estimate the emissions from oil from different sources, or the carbon intensity, extending from initial oil exploration to the arrival of the oil at the refinery gate.[21]

Since 2012 the California Air Resources Board (CARB) has provided carbon intensity estimates for all oils refined in California, measured in grams CO_2 per megajoule (g/MJ — grams of CO_2eq produced per MJ of energy derived from oil).[22] The carbon intensity values are attributed to the production and transport of the crude oil supplied as petroleum feedstock to California refineries, so emissions that occur during the refining process or thereafter are not considered. Carbon intensity (CI), as a measure of greenhouse gas emissions derived from a given crude, is one way to quantify the relative harms of different crudes to the climate.

Using the carbon intensity values of the various refined oils, CARB calculates an average carbon intensity for a given year by doing a weighted average based on the volume of oil from a given source:

$$\text{Average carbon intensity} =$$

$$\frac{(Crude\ Vol.\#1 * CI\ \#1) + (Crude\ Vol.\#2 * CI\ \#2) + (Crude\ Vol.\#3 * CI\ \#3) + \cdots}{Total\ Volume\ of\ Oil\ Refined\ in\ CA}$$

where “crude vol.” is the amount of oil from a given source and “CI” is the corresponding carbon intensity of that oil.

For our study, we used the same method and CARB’s own average carbon intensity values of individual crudes to determine the average carbon intensity of different subsets of oil refined in California, including the average carbon intensity of only oils produced in California and only oils produced outside of California. The following is an example calculation of the average carbon intensity of oil from California oilfields:

$$\text{Average carbon intensity of CA oil} =$$

$$\frac{(Crude\ Vol.\ CA\ \#1 * CI\ CA\ \#1) + (Crude\ Vol.CA\ \#2 * CI\ CA\ \#2) + (Crude\ Vol.CA\ \#3 * CI\ CA\ \#3) + \cdots}{Total\ Volume\ of\ Oil\ Produced\ and\ Refined\ in\ CA}$$

where “crude vol. CA” is the amount of oil from a given California oilfield and “CI CA” is the corresponding carbon intensity of that oil.

Using a conversion factor of 5,813.4 MJ per barrel as an approximation,[23] all carbon intensity values in the following analysis were converted from grams CO_2 per megajoule to kilograms CO_2eq per barrel (kg CO_2eq/bbl). With carbon intensity in terms of barrels and using values for barrels of oil production, upstream emissions from oil refined in California between 2012 and 2019 were also estimated.

Oil field in Bakersfield by Babette Plana/Flickr

Results

The carbon intensity of oil produced in California has increased 22% since 2012, increasing the overall carbon intensity of all crude refined in the state.

The average carbon intensity of all crudes refined in California has gone up 10% between 2012 and 2019, increasing from an average of 66 kg CO_2eq/barrel in 2012 to 73 kg CO_2eq/barrel in 2019. This is an increase of about 1.5% per year. Meanwhile, for just the crudes extracted from California oilfields, the average carbon intensity has gone up 22% between 2012 and 2019, increasing from 81 kg CO_2eq/barrel in 2012 to 98 kg CO_2eq/barrel in 2019. This is an increase of about 3.1% per year or double the rate of increase for the carbon intensity of all oils refined in California. For all crudes not produced in California, the average carbon intensity has gone up 8% between 2012 and 2019, increasing from 59 kg CO_2eq/barrel in 2012 to 64 kg CO_2eq/barrel in 2019. This is an increase of about 1.2% per year, or about half the increase observed for crudes produced in California (Table 1, Figure 1).

So, although the average carbon intensity of all oil refined in California is increasing, the average carbon intensity of California-produced oil is increasing far faster: twice the rate of all oils refined in California, and nearly three times the rate of oils originating outside of California. This complements an earlier estimate that the carbon intensity of California crudes on a per barrel basis increased by 39% between 2000 and 2017.[24]

Year	All Crude Refined in CA	CA-Produced Crude	Crude Produced Outside CA
2012	66.04	80.57	58.89
2013	66.10	80.63	58.72
2014	65.05	82.26	56.45
2015	70.11	86.97	61.80
2016	70.57	87.55	62.67
2017	69.35	87.72	62.32
2018	71.80	97.20	62.96
2019	72.78	98.07	63.66

Table 1: Average carbon intensity (CI) of oil refined in California between 2012 and 2019 in units of kg CO_2eq/barrel: (1) all crude refined in CA; (2) CA-produced crude; (3) crude produced outside CA.

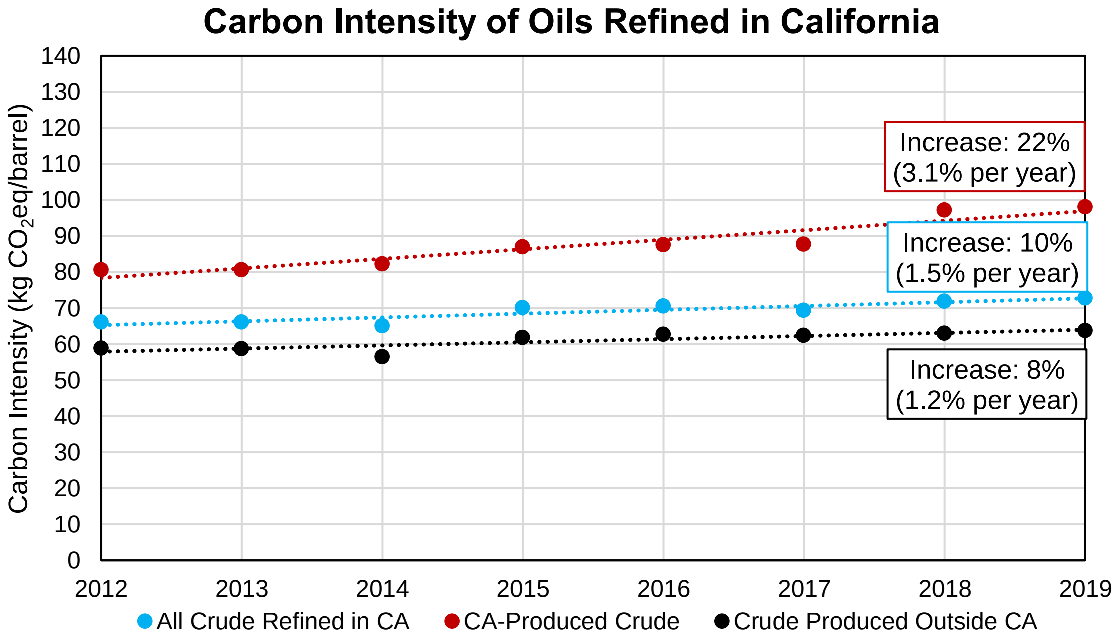

Figure 1: Increase in average carbon intensity over time for: (1) all crude refined in CA; (2) CA-produced crude; (3) crude produced outside CA.

<u>The high carbon intensity of California-sourced oils can be traced to just a few key California oilfields.</u>

As of 2019, California had 158 major oilfields, but five oilfields contributed more to California's average carbon intensity and upstream emissions than all others combined. These five fields in order of decreasing contribution are Midway-Sunset, South Belridge, Cymric, Kern River and San Ardo. Between 2012 and 2019, Midway-Sunset contributed 22% of the estimated upstream emissions from California-sourced oils; South Belridge contributed 12%; Cymric contributed 10%; Kern River contributed 9% and San Ardo contributed 8%. The remaining 39% was contributed by the other 153 major California oilfields (Figure 2):

Figure 2: The top 5 California fields in terms of their contributions to the average carbon intensity and upstream emissions of California-sourced oils between 2012 and 2019. "All other" refers to all California oilfields outside of the top 5.

The contribution of specific oilfields to the average carbon intensity of California-sourced oils is strongly linked to total oil production (Figure 3), with Midway-Sunset, Kern River, South Belridge and Cymric being in the top five for contributing to California-sourced oils' average carbon intensity and the top five for California oil production. San Ardo, though in the top five for its contribution to California carbon intensity, ranks eighth in terms of oil production. The discrepancy is due to the relatively high carbon intensity of San Ardo oil.

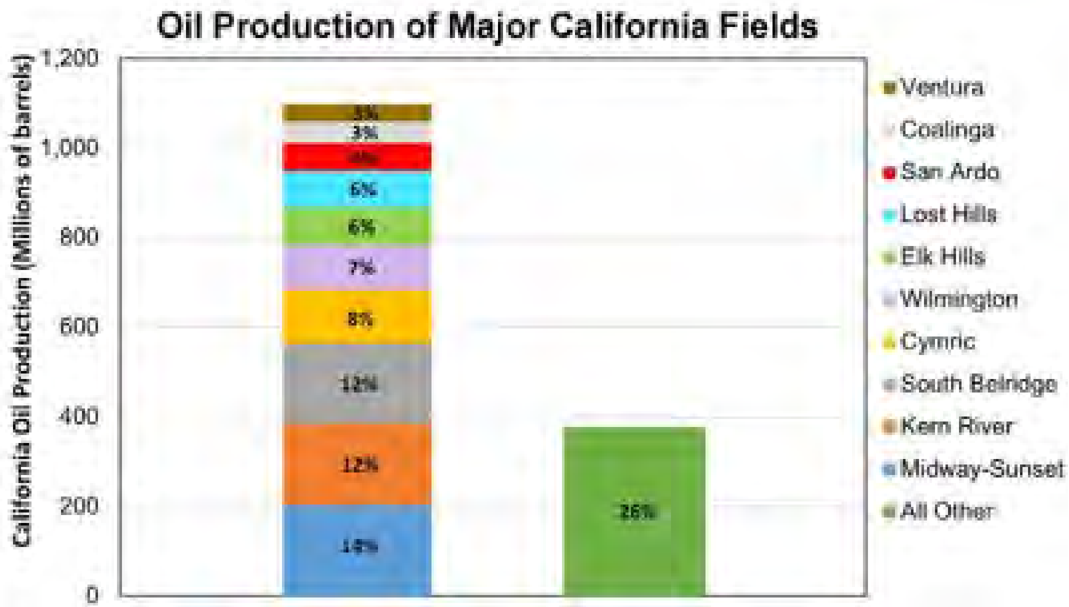

Figure 3: California's top 10 oilfields in terms of cumulative oil production between 2012 and 2019. Percent values displayed represent the percent of total California oil production. "All other" refers to all California oilfields outside of the top 10.

In terms of their contribution to the average carbon intensity of California-sourced oils, none of the top five California oilfields are in the top five for individual carbon intensity, although all are in the top 20 (Figure 4). This highlights the importance of both carbon intensity and production volume in determining the contribution of any given oilfield to the average carbon intensity and upstream emissions.

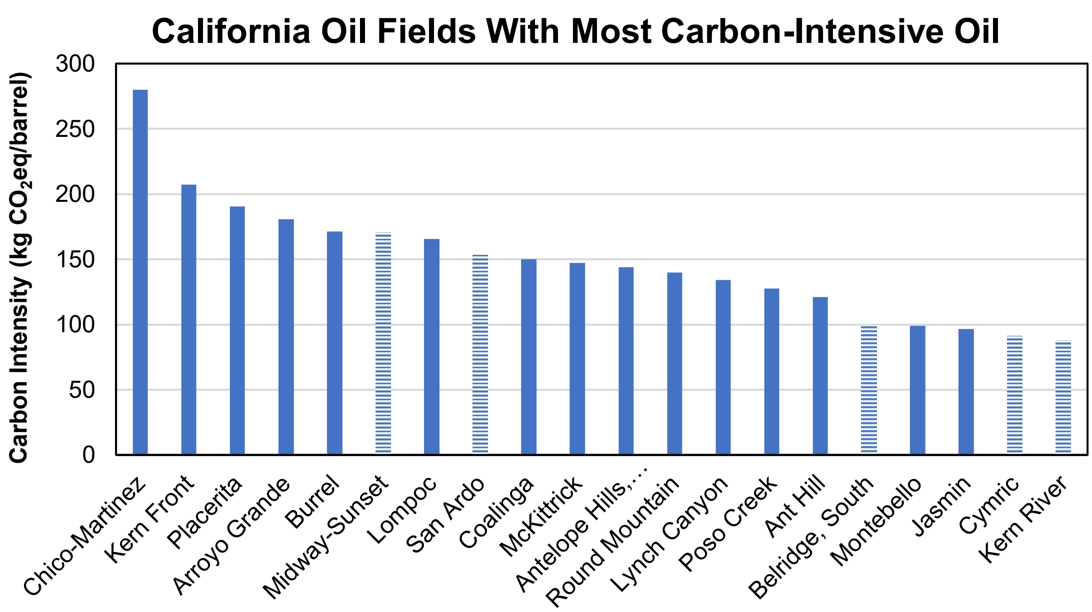

Figure 4: California's top 20 oilfields based on carbon intensity in 2019. The top 5 based on their contribution to the total upstream emissions of California-sourced oils are distinguished with horizontal stripes.

Top 10 Most Productive California Oilfields vs. Top 10 Carbon Dioxide Emitters

It's no surprise that California's top oil-producing fields also tend to contribute the most to California oil's upstream carbon dioxide emissions. Eight of the top 10 emitters are also in the top 10 for oil production. That means the fields producing the most oil also produce some of the dirtiest and most damaging crude, worsening California's overall contribution to dangerous global heating.

California oil is now more carbon intensive than notoriously dirty Canadian tar sands crude.

Our 2017 study found that three quarters of oil produced in California was as climate-damaging as Canadian tar sands crude, which is infamous for being exceptionally dirty.[25] This report shows that California oil has become more carbon intensive since that time.

In 2019 the average upstream carbon intensity of California oil exceeded that of Canadian tar sands crude with about 98 kg CO_2eq/barrel for California oil and about 90 kg CO_2eq/barrel for Canadian tar sands crude refined in California. Moreover, between 2012 and 2019, the average carbon intensity of Canadian tar sands crude refined in California declined, while the average carbon intensity of California-sourced oil increased (Figure 5). This may be due to California refineries refining proportionally less of the dirtiest Canadian oils over time.

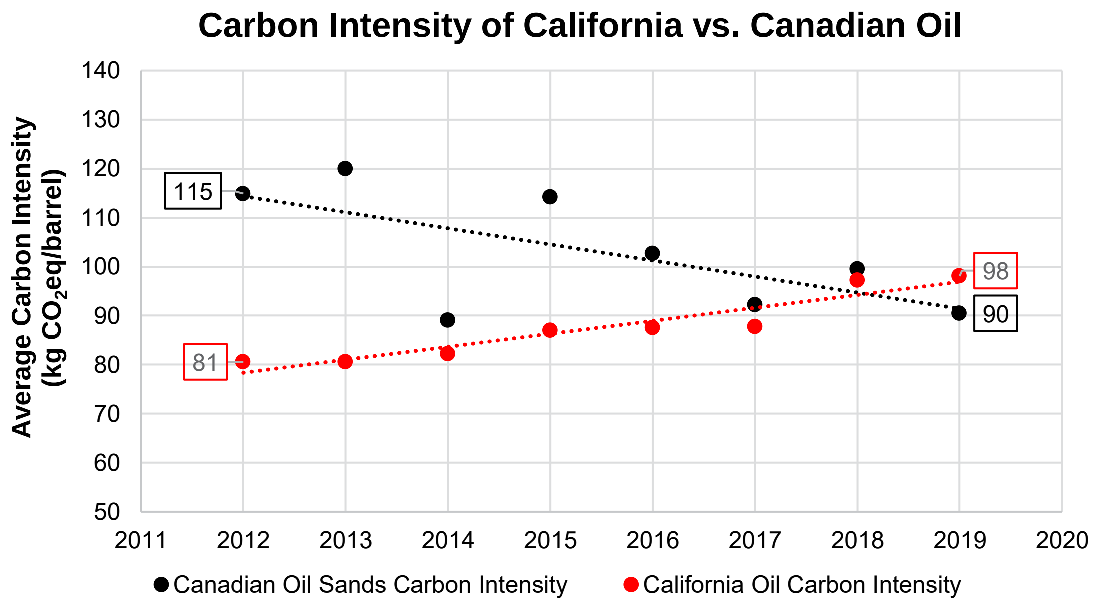

Figure 5: Change in average carbon intensity over time of Canadian oil sands crude vs. California-sourced oil. Here, average carbon intensity and average upstream emissions are interchangeable.

The last point is evidenced by the difference in the range of carbon intensities of Canadian crudes between 2012 and 2019. In 2012, the range was 44 to 142 kg CO_2eq/barrel, whereas in 2019 it was 47 to 171 kg CO_2eq/barrel. Even though the range shifted up in 2019, indicating dirtier oil streams being refined from Canada, the overall average carbon intensity was less in 2019 than in 2012, meaning a smaller proportion of these dirtier oils were refined.

Tar sands in Alberta
by Dru Oja Jay, Dominion

The increase in carbon intensity of California-sourced oils is partially canceling out the benefits of the decline in California oil production.

California's oil production has been in long-term decline since 1985 (Figure 6):

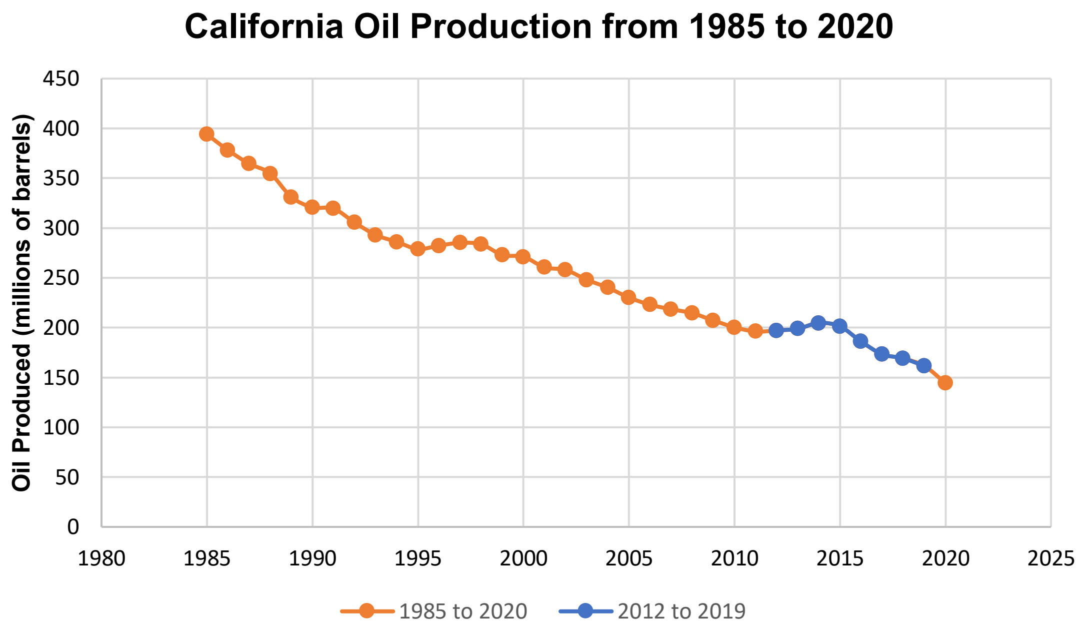

Figure 6: California oil production from 1985 to 2020.[26]

This trend holds in the 2012 to 2019 timeframe of our analysis, with the first three years holding a relatively steady annual amount of oil production, and 2015 to 2019 seeing declines in both oil production and upstream emissions from California-sourced oils (Figure 7).

However, the rate of decline in oil production from 2015 to 2019 exceeded the rate of decline in upstream emissions. While oil production declined by 22% between 2015 and 2019, upstream emissions only declined by 13%. If we compare 2012 and 2019, oil production was 20% less in 2019 than in 2012, whereas upstream emissions were only 3% less. Both cases make clear that the increase in carbon intensity of California-sourced oils is partially canceling out the climate benefits of California's oil-production decline.

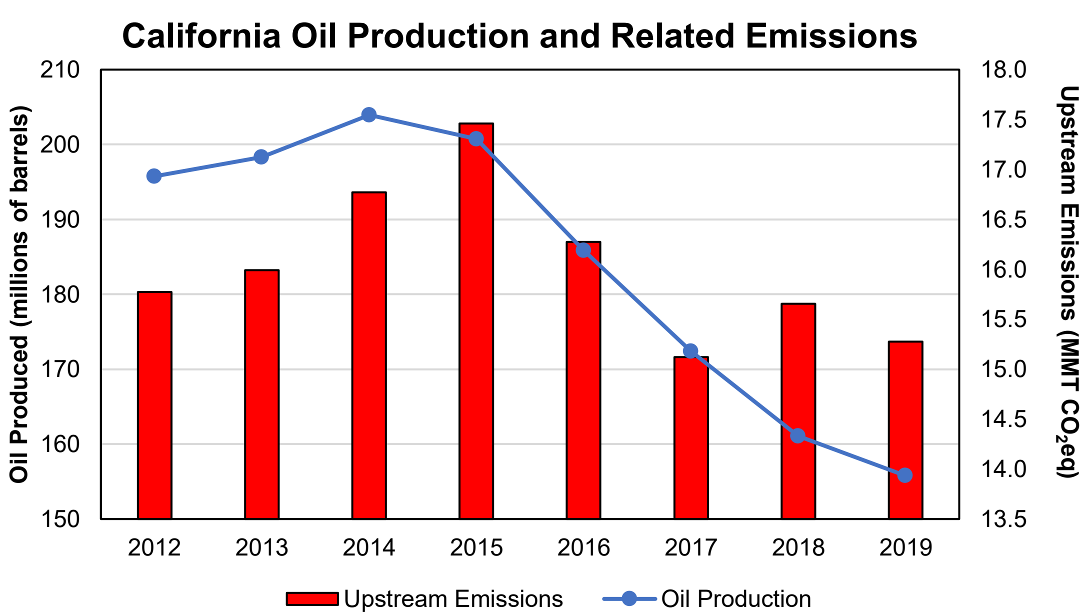

Figure 7: Upstream emissions from California-sourced oils vs. California oil production between 2012 and 2019.

For example, upstream emissions in 2015 were about 18.1 MMT CO_2eq. So if upstream emissions declined by 22% between 2015 and 2019, as oil production did, then emissions in 2019 would be about 14.1 MMT CO_2eq. Instead upstream emissions in 2019 were 15.8 MMT CO_2eq, or about 1.7 MMT CO_2eq more. Assuming this value is 20% of lifecycle emissions (upstream emissions + midstream refining emissions + downstream end use emissions; assumption addressed in more detail in the Discussion), then the lifecycle emissions would be about 8.5 MMT CO_2eq more, or an additional 2% of California's total emissions (based on a 2018 estimate of California total emissions).

Thus, increasing carbon intensity is reducing California's potential progress on reducing greenhouse gas emissions. To maximize emissions reductions, policymakers should both reduce oil production and eliminate enhanced oil-recovery techniques that increase the carbon intensity of California oils.

San Ardo Oil Field by
Drew Bird Photography

Discussion

A phaseout of California oil production does not require an increase in imports.

Proponents of business-as-usual oil extraction in California often say that limiting oil production in California will require an increase in imports from parts of the world where oil is produced with fewer environmental safeguards. This is simply incorrect.

A 2018 study found that the decline in production that would result if California stopped approving new oil wells would be approximately equal to the decline in oil consumption forecast by the California Air Resources Board's (CARB's) "Scoping Plan" to reduce greenhouse gas emissions (Figure 8).[27] Ending the approval of new oil wells and accelerating the ongoing decline in the state's oil production would, therefore, not require an increase in imports.

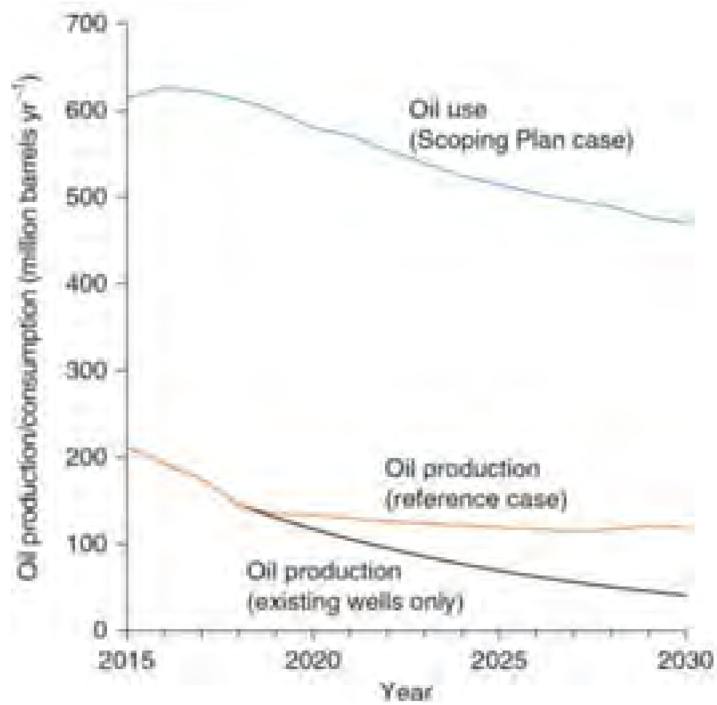

Figure 8: California's projected decline in oil production and consumption. (1) Reference scenario (orange line): developed by the U.S. Energy Information Administration, the state's annual oil production decline trajectory if it continues issuing new drilling permits; (2) No new wells (black line): production drawdown if California stopped issuing drilling permits; (3) Scoping Plan scenario (blue line): estimate of future oil use based on California's Scoping Plan (for gasoline, diesel and liquefied petroleum gas), the federal government (for residual and other oil), and the federal government and the California Energy Commission (for jet fuel). Figure and data from Erickson, P. et al. (2018).[28]

An update to the findings of the 2018 study using data from a 2020 CARB-commissioned study that charted three pathways for California carbon neutrality by 2045 strengthens this conclusion. Under CARB's "Balanced" and "Zero Carbon Energy" scenarios, the decline in California oil demand between 2020 and 2030 would exceed the decline in oil production if the state stopped issuing permits for new oil wells.[29] Thus, under California's current climate policies, California can and should simultaneously reduce in-state oil production and oil imports.

In 2020 oil production in California dropped to 144 million barrels, or by 10.6% compared to 2019.[30] According to state regulators, only 138 new wells were drilled, despite the issuance of permits for nearly 2,000 new wells.[31] Meanwhile, imports dropped by 27% from 433 million barrels to 316 million barrels.[32]

These declines are largely because of less oil consumption during the COVID-19 pandemic, but this further emphasizes the point that as California oil demand decreases, declines in production from halting new oil well permits would not need to be compensated for with increases in imports. With decreasing demand, in a no-new-permits scenario, both production and imports would decline, leading to a global decline in fossil fuel reliance.

However, research by Communities for a Better Environment reveals a troubling trend: In recent years California refineries have increased their production of gasoline for *export* to Pacific Rim countries, maintaining demand for imports despite falling oil use within the state.[33] If California allows this trend to continue, then it will continue to prop up imports. This emphasizes the need for the state to pursue a just transition that winds down all phases of the fossil fuel lifecycle, including refining.

A phaseout of oil extraction in California would not only get rid of an exceptionally dirty source of crude, but it would also lead to an overall global reduction in oil production and decrease in global carbon emissions. This is because every barrel of California oil left in the ground will reduce overall oil supply, resulting in a net decrease of about half a barrel of oil consumption globally.[34] Thus, actions taken in California to curb oil production will have global ramifications.

California's oil and gas regulatory failures have worsened the state's public health and environmental justice crises.

The oil industry's argument that production limits here will cause more production in places with weaker environmental safeguards is not only wrong, but also morally reprehensible because it minimizes California's regulatory failures and the public health and environmental justice crises caused by in-state oil production.

California's long-term regulatory failures are shocking and include the following:

- California is virtually the only major oil-producing state with no minimum setback distance between wells and homes, schools or other sensitive receptors, despite the grave health harms from oil and gas pollution.
- An EPA audit in 2011 found widespread failures in enforcing state regulations pertaining to the safety of oil and gas-related underground injection projects.[35]
- The California Geologic Energy Management Division (CalGEM) admitted in 2015 that thousands of oil and gas wells were improperly injecting wastewater into California's protected underground sources of drinking water, leading to the widespread contamination of the state's water supplies.[36] Half a decade later, the state has reneged on multiple commitments to remedy the situation and our water supplies are still being sacrificed to the oil industry.[37]
- California's lax waste-disposal laws allow oil industry wastewater to be dumped into unlined pits, which has led to multiple additional instances of groundwater contamination.[38]
- Loosening regulations on steam injection pressure led to multiple large-scale spills in Central California in 2019. CalGEM has yet to collect any fines for a 1.3-million-gallon spill in the Cymric oilfield,[39] and a separate spill of over 4 million gallons is still ongoing.[40] These spills contaminate the environment and threaten wildlife.
- Reports uncovered that multiple regulators had financial interests in oil companies,[41] and numerous top agency officials have gone on to work for the industry.
- Dozens of injection projects were approved under "dummy" files that had no underlying review for the project.[42]
- CalGEM has brought virtually no enforcement actions in response to illegal pollution.[43]
- CalGEM also has failed to comply with the environmental review and public participation requirements of the California Environmental Quality Act, despite acknowledging the environmental harms of extraction.[44]

California's regulatory record on oil and gas does not justify claims that it has the toughest environmental regulations in the world. On the contrary, it highlights the urgent need to phase out dangerous and dirty fossil fuel production in the state.

Lifecycle emissions make California oils' climate harms even more pronounced.

The carbon intensity values provided by the Air Resources Board only consider upstream emissions from oil, or the emissions from extracting and transporting oil up to the refinery gate. However, every step of the fossil fuel life cycle produces greenhouse gas pollution, including midstream refining and downstream combustion.

While we take comparisons of the upstream data from CARB as representative of the relative "dirtiness" of different oils refined in California, the overall climate impact of oils refined in California depends on the total lifecycle emissions. The emissions from midstream and downstream processes typically exceed upstream emissions. This is apparent when considering previously reported lifecycle emissions of California's top five oils in terms of upstream emissions — Midway-Sunset, South Belridge, Cymric, Kern River and San Ardo (Table 2):[45]

Field	2017 Upstream Emissions (kg CO_2eq/bbl)	2017 Lifecycle Emissions (kg CO_2eq/bbl)	% Upstream Emissions
Midway-Sunset	146	725	20%
South Belridge	86	690	12%
Cymric	112	600	19%
Kern River	56	650	9%
San Ardo	159	760	21%

Table 2: For California's top oilfields in terms of upstream emissions, listed are the upstream emissions estimates from 2017, most recent lifecycle emissions estimates from 2017, and upstream emissions per barrel as a percentage of lifecycle emissions per barrel.

Comparing the 2017 (the year with the most recent lifecycle emissions data) upstream and lifecycle emissions of the top five fields, we find that midstream and downstream processes constitute a greater proportion of emissions than upstream processes. Taking the above five fields as an example, upstream emissions are most often around 20% of the total lifecycle emissions. This agrees with an estimate by the Stockholm Environmental Institute in which factoring in upstream emissions increases the total emissions per barrel of oil by at least 25%,[46] which would likewise make upstream emissions about 20% of the total.

Putting this into perspective, California's total CO_2eq emissions across all sectors in 2018 was 425 MMT CO_2eq. In just 2018, upstream emissions from California-sourced oil were about 16 MMT CO_2eq. Assuming upstream emissions are about 20% of total lifecycle emissions, lifecycle emissions from California-sourced oil in 2018 would be about 80 MMT CO_2eq, which would make them almost 20% of California's total emissions in 2018 (Table 3).

Year	Oil Production (bbl)	Upstream Emissions (MMT CO_2eq)	Lifecycle Emissions (MMT CO_2eq)	Total CA Emissions (MMT CO_2eq)	% Upstream Emissions	% Lifecycle Emissions
2012	196	15.8	78.9	451.6	3.5%	17%
2013	198	16.0	80.0	447.6	3.6%	18%
2014	204	16.8	83.9	443.4	3.8%	19%
2015	201	17.5	87.3	440.8	4.0%	20%
2016	186	16.3	81.4	429.2	3.8%	18%
2017	172	15.1	75.6	424.5	3.6%	18%
2018	161	15.7	78.3	425.3	3.7%	18%
2019	156	15.3	76.4	--	--	--

Table 3: For the years 2012 to 2019, listed are barrels of California oil production, estimated California upstream emissions, estimated lifecycle emissions assuming upstream emissions are 20% of lifecycle emissions, and total California emissions across sectors. Using those values, upstream and lifecycle emissions as a percentage of total California emissions were calculated and listed.

The importance of considering lifecycle emissions is even more apparent when looking at the carbon intensity of California's refining itself. As follows from California both producing and accepting some of the dirtiest oil for refining, California's refining processes are exceptionally dirty.

Because California refines the heaviest crude on average, California refineries emit more CO_2eq per barrel of crude refined than those in any other major U.S. refining region. For 2013 to 2017, the average carbon intensity of California refining was 59.3 kg CO_2eq/barrel, whereas the U.S. average over the same time was 49.3 kg CO_2eq/barrel. Some individual refineries in California have refining carbon intensities as high as 79 kg CO_2eq/barrel.[47]

California-sourced oil's excessive upstream emissions burden not only California's population but the entire planet with some of the world's dirtiest refining.

California's Gas Production is More Climate-Damaging Than Coal And Threatens Public Health and Safety.

While California is the seventh-largest oil producer and third-largest oil refiner, it ranks 14th in U.S. fossil gas production, with nearly 200 billion cubic feet produced in 2019. California's gas production, however, is also exceptionally dirty, dangerous and carbon intensive.

A recent report from the California Energy Commission assumes fossil gas as part of California's energy mix well into the future, treating it as a bridge fuel. However, methane — a superpollutant 87 times more powerful than CO2 at warming the climate over a 20-year period — leaks during all phases of oil and gas production.

If the methane leakage rate is greater than 2.4% of the gas produced, then the climate damage from the methane leakage cancels out any climate benefit that gas achieves over coal at the smokestack over a 20-year period.

Therefore, depending on the overall leakage rate, fossil gas provides little or no climate benefit over coal: In fact, fossil gas may even be worse.

A recent analysis found that the methane leakage rate in the San Joaquin Valley is 4.8%, making gas sourced from this region not only worse than coal on a 20-year timescale, but also the worst in the continental United States.

In addition to its role as a major climate pollutant, gas production also threatens public health and safety. The 2015 gas leak disaster at the Aliso Canyon gas storage facility near Los Angeles resulted in 109,000 metric tons of methane entering our atmosphere—the largest-known methane release in U.S. history.

The Aliso Canyon disaster boosted statewide greenhouse gas emissions, set back emissions-reduction goals and sickened nearby residents with symptoms including dizziness, headaches, nausea, eye, nose and throat irritation, nose bleeds and likely long-term effects yet to be identified. Clearly the risks of keeping gas infrastructure in place far exceed any benefits.

Though California's dirty oil is the focus of the present study, it must be considered in the context of California's overarching dirty fossil fuel industry. The continued extraction of both exceptionally dirty oil and gas only makes a stronger case for the rapid phaseout of fossil fuels to mitigate substantial climate and public health harms.

Conclusion

Because climate change is driven primarily by fossil fuel production and combustion, most of the world's fossil fuels must stay in the ground to avoid the worst dangers of climate change. Worldwide, there are more than enough fossil fuels in already developed production fields to far exceed targets to limit warming to 1.5 degrees C or even 2 degrees C.[48] New fossil fuel development and infrastructure is thus unsafe and unjustified, and fossil fuel production must be phased out globally within the next several decades. With one of the world's wealthiest economies and some of the world's dirtiest oil, California needs to lead the way in ending fossil fuel production.

To address the climate damage, health harms and environmental injustice caused by its increasingly dirty oil production, Gov. Newsom should direct his regulators to end approvals for new oil and gas wells and other fossil fuel projects and commit to a plan to phase out existing extraction far faster than 2045. Newsom should also act now, not in 2024, to ban fracking and related extreme techniques that amplify the damage from extraction. Newsom should immediately implement a health-and-safety buffer to prevent oil and gas drilling in communities and protect public health and safety from the air pollution and other harms of oil and gas extraction. Without taking these crucial steps, California cannot protect the climate or the state's most vulnerable communities.

Inglewood Oil Field by
Gary Kavanagh

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Appendix

California-sourced oil is the primary contributor to the average carbon intensity of all oil refined in California.

Although California oil was about 31% of all oil refined in California between 2012 and 2019, it was responsible for about 39% of the carbon intensity, or about 39% of the emissions leading up to the refinery gate (upstream emissions).

Calculated using the carbon intensity values provided by CARB, it is estimated that upstream emissions of oils refined in California between 2012 and 2019 were about 343 million metric tons CO_2eq (MMT CO_2eq). It follows that oil not produced in California constituted about 69% of all oil refined in California but was responsible for only 61% of the emissions leading up to the refinery gate.

As a reference, if all oils refined in California had the same carbon intensity, then their contribution to the total emissions leading up to the refinery gate would be the same as their contribution to the total volume of oil refined in California. So, a contribution to the carbon intensity that is more than the contribution to total oil refined indicates a carbon intensity above the overall average. In turn, a contribution to the carbon intensity that is less than the contribution to the total volume of oil refined indicates a carbon intensity below the overall average. This further indicates that, on average, California oil is more polluting per barrel than the rest of the global supply refined in California.

This fact holds when considering just the oil produced in the U.S. that is refined in California. Oil produced in the U.S., including oil produced in California, constitutes 46% of the oil refined in California, but 54% of the upstream emissions. However, if broken down further, oil produced in the U.S. *excluding* oil produced in California constitutes 15% of the oil refined in California but 16% of the upstream emissions.

In other words, the contribution of U.S. oil, including California, to upstream emissions is 1.2 times its contribution to the total production. The contribution of U.S. oil, excluding California, to upstream emissions is 1.05 times. And the contribution of California oil to the total upstream emissions is 1.3 times its contribution to the total production. So, normalized to production, oil produced in California contributes more to the upstream emissions for California-refined oils than other U.S. oils (Figure 9).

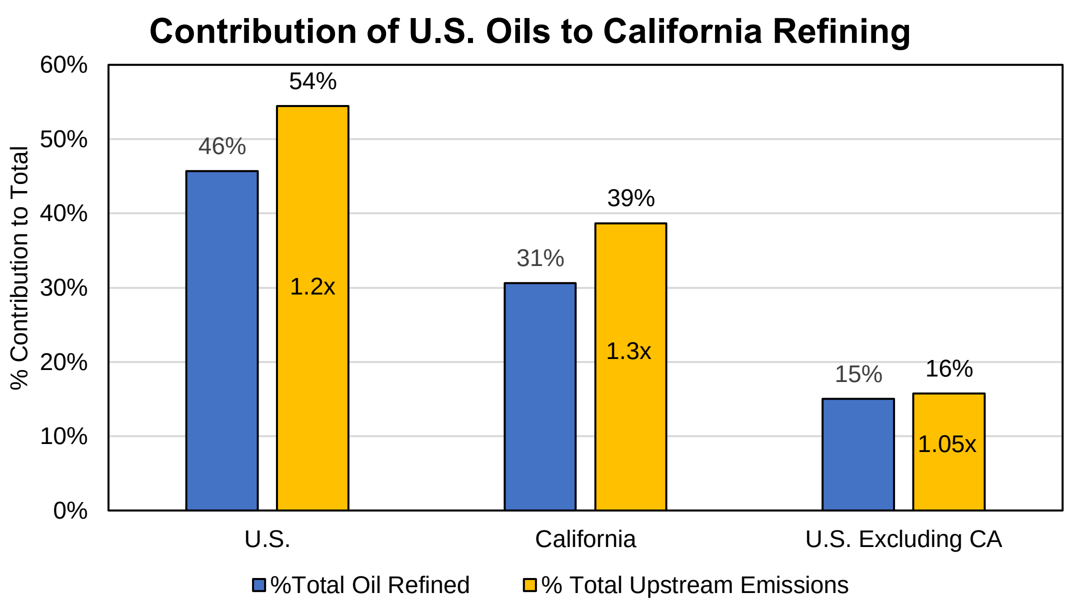


Figure 9: For U.S.-sourced oil including California, California-sourced oil, and U.S.-sourced oil excluding California, the volume of oil as a percentage of all oil refined in CA (% Total Oil Refined) vs. oil as its percent contribution to the total upstream emissions of all oil refined in CA (% Total Upstream Emissions). Also labeled on the orange bars is the multiple by which a given region's contribution to the total upstream emissions compares to its contribution to the total oil refined. Here, the contribution to average carbon intensity and the contribution to upstream emissions are interchangeable.

<u>There is strong overlap between California fields employing enhanced oil recovery techniques and those with the most upstream emissions.</u>

Enhanced oil recovery techniques such as cyclic steam and steamflooding are known to be energy-intensive compared to conventional oil extraction with the result being greater associated greenhouse gas emissions. In California, 19 fields have cyclic steam wells (Figure 10) while 18 fields have steamflood wells (Figure 11), with significant overlap of the two groups.

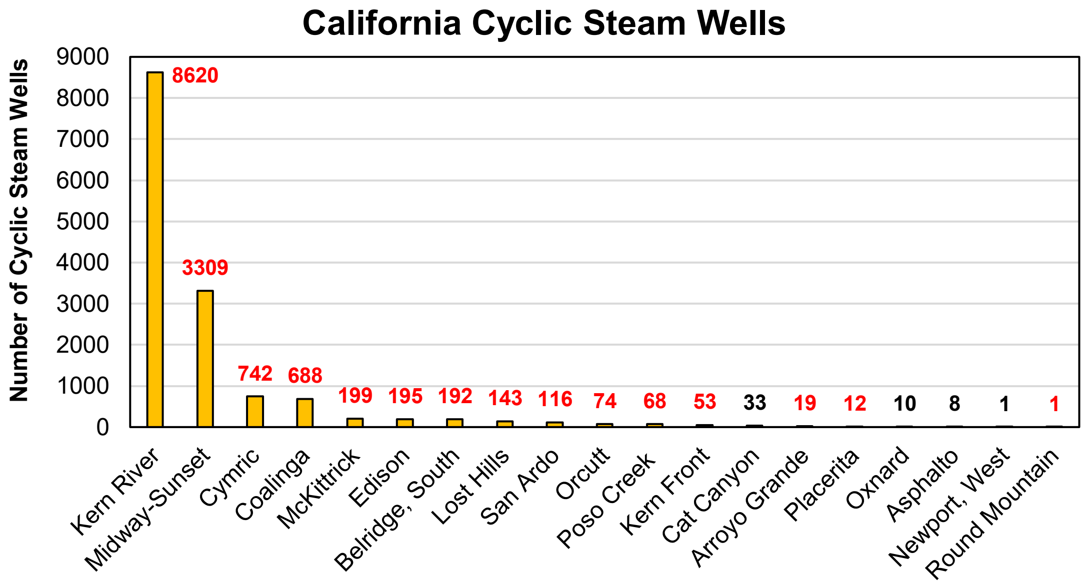


Figure 10: Cyclic steam wells in California based on 2020 data. The number of cyclic steam wells in each oilfield is labeled. The oilfields that are also in the top 20 for upstream emissions have red labels.

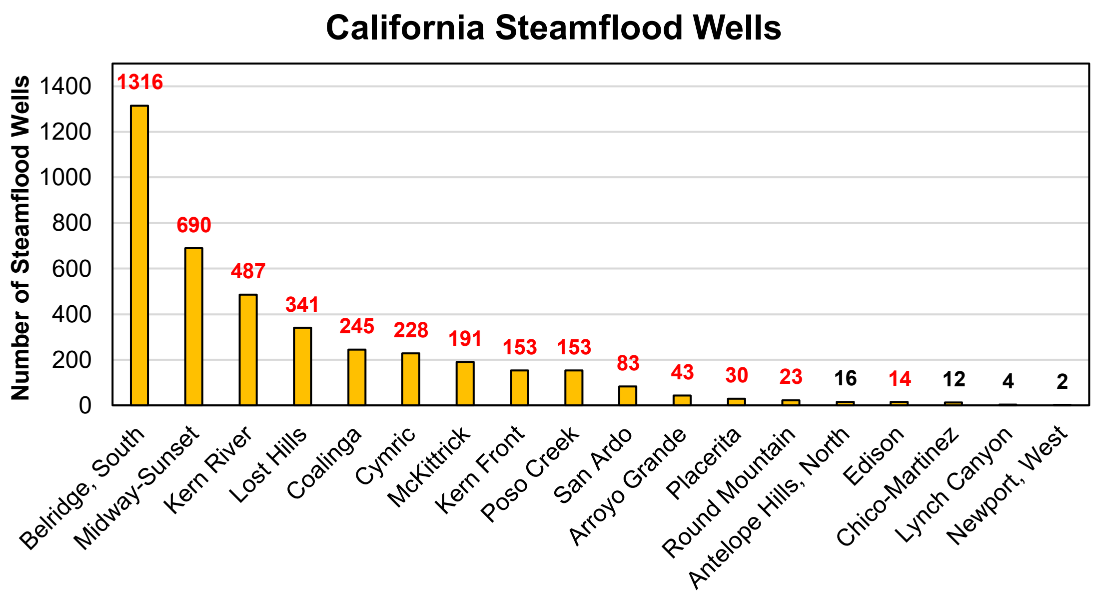


Figure 11: Steamflood wells in California based on 2020 data. The number of steamflood wells in each oilfield is labeled. The oilfields that are also in the top 20 for upstream emissions have red labels.

Notably, of the 19 oilfields with cyclic steam wells, 15 rank in the top 20 for their contribution to upstream emissions from California-sourced oils. Of the 18 oilfields with steamflood wells, 14 rank in the top 20 for their contribution to upstream emissions. Also, four of the top five oilfields in terms of upstream emissions rank highly in terms of numbers of steam wells: Kern River, Midway-Sunset, and Cymric are 1, 2, and 3, respectively, for number of cyclic steam wells while South Belridge, Midway-Sunset, and Kern River are 1, 2, and 3, respectively, for number of steamflood wells. The top five oilfields for upstream emissions (the four mentioned, plus San Ardo) together have 70% of California's steamflood wells and 90% of California's cyclic steam wells, or 85% of California's total steam wells (cyclic steam + steamflood).

<u>There is significant overlap in California between fracking permits, enhanced oil recovery and the most carbon-intensive oil extraction.</u>

In 2020, 1,929 oil and gas drilling permits were issued in California with 1,052 of them, or 55%, going to the top five fields contributing the most to greenhouse gas emissions. Of the top five fields, South Belridge received the most with 351, then Midway-Sunset with 346, Cymric with 221, Kern River with 111 and San Ardo with 23.

Of the total permits, 1,359 were for oilfields in the top 20 for carbon intensity (Figure 6).

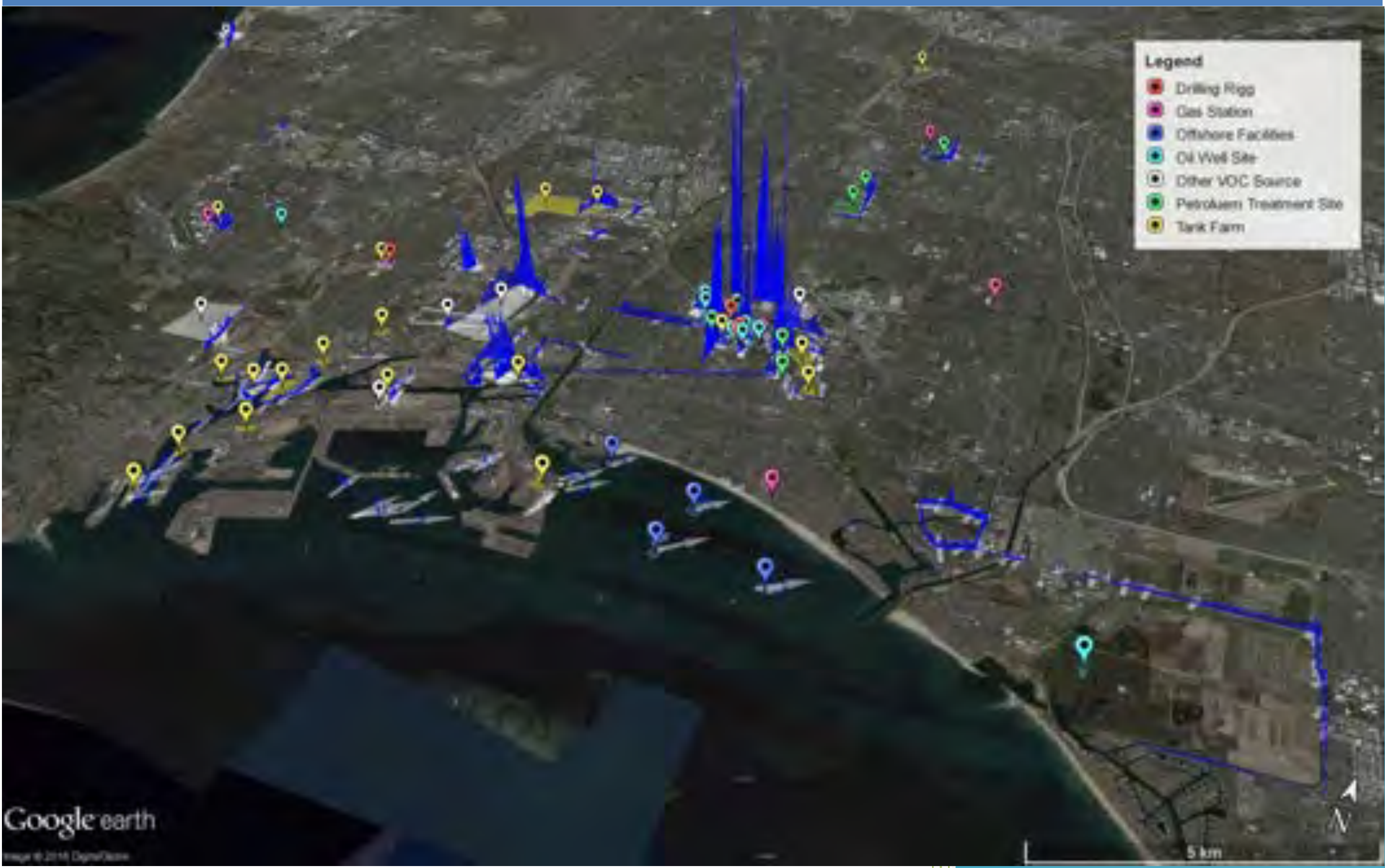
Finally, of the total permits, 65 were for cyclic steam wells and 64 were for steamflood wells. Out of the 129 total cyclic steam and steamflood well permits, 78 permits, or 60%, were for fields in the top five for greenhouse gas emissions.

In 2020, 84 permits for fracking were issued with 24, or 29%, for South Belridge. Another 36, or 43%, were issued for Lost Hills Oil Field. Lost Hills has not been previously mentioned, but it is noteworthy as number seven in terms of oilfield greenhouse gas emissions. The remaining permits were granted to North Belridge which is number 22 in terms of oilfield greenhouse gas emissions.

As is the case with existing enhanced oil recovery wells, the oilfields being granted oil and gas drilling and fracking permits are those that already contribute the most to California oil's greenhouse gas emissions, hence maintaining a vicious cycle.

2015

Using Solar Occultation Flux and other Optical Remote Sensing Methods to measure VOC emissions from a variety of stationary sources in the South Coast Air Basin



FluxSense

FINAL REPORT

FluxSense AB

14 September 2017

Date: 14 September 2017

Title: Using Solar Occultation Flux and other Optical Remote Sensing Methods to measure VOC emissions from a variety of stationary sources in the South Coast Air Basin.

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FluxSense Inc. is subsidiary of FluxSense AB (www.fluxsense.se; San Diego, CA). FluxSense started as a spin-off company from research conducted at Chalmers University of Technology in Sweden and has been active for more than 10 years. FluxSense has carried out more than 70 industrial site surveillances in Austria, Belgium, Denmark, France, Middle East, Netherlands, Norway, Sweden and the US.

[Cover: Visualization of alkane (blue curves) plume transects from multiple SOF measurements conducted at selected locations during this study (not a complete data set). Note that data was generated from multiple days and various wind conditions. The apparent height of the blue line is proportional to the integrated vertical column concentration expressed in mg/m^2. The white arrow indicates approximate wind direction and speed during the measurements. Image mapped on Google Earth © 2016.]

Executive summary

BACKGROUND

Industrial emissions of volatile organic compounds (VOC) contribute to the formation of ground level ozone, which constitutes a public health concern especially in urban areas. To better characterize such emissions in the South Coast Air Basin (SCAB) and to assess their impact on ambient pollution levels, the South Coast Air Quality Management District (SCAQMD) has promoted and sponsored a series of measurement projects using optical remote sensing methods. These projects include experimental studies of emissions from refineries, oil depots, treatment facilities, oil wells, gas stations, fuel islands and barges. Investigations of various types of sources were separated into three projects:

- **Project 1**: Emission Measurements of VOCs, NO_2 and SO_2 from the refineries in the South Coast Air Basin using Solar Occultation Flux and other Optical Remote Sensing Methods
- **Project 2**: Using Solar Occultation Flux and other Optical Remote Sensing Methods to measure VOC emissions from a variety of stationary sources in the South Coast Air Basin
- **Project 3**: Remote Quantification of Stack Emissions from Marine Vessels in the South Coast Air Basin

In addition, SCAQMD has sponsored technology demonstration and validation studies to assess uncertainties associated with different optical techniques through side-by-side measurements of actual sources and controlled source gas releases.

Several research studies, including a FluxSense 2013 pilot project (also sponsored by SCAQMD) suggest that emissions of VOCs from industrial activities are substantially underestimated compared to emission inventories. Systematic underestimation of VOC emissions from the petroleum industry, such as large refineries, has been observed in various areas of the US and around the world during multiple measurement surveys. The project described herein studied emissions from smaller sources such as oil wells, intermediate storage tanks and gas stations. In Los Angeles, these small sources are spread out over the entire Basin and many are located in the immediate proximity of residential areas. Overall, these sources are likely to contribute substantially to smog formation and negatively impact air quality in the region. Thus, a systematic and quantitative assessment of such emissions is required to take appropriate and effective actions, reduce the VOC burden and better understand the extent of any related VOC exposure issues.

METHODOLOGY

This report covers studies of gas emission measurements of alkanes, BTEX (i.e. benzene, toluene, ethyl-benzene and xylenes), methane and, in some cases, ammonia from 62 separate sites belonging to eight different source categories in the SCAB (Table ES. 1). The measurements described in this document stretched from the beginning of September to middle November 2015 and included over 900 individual surveys.

Given the large number of industrial sites in the SCAB and the difficulty to appropriately assess their emission contributions, it is very important to utilize state-of-the-art mobile measurement methods for measuring such emissions in real-time. In this study, emission fluxes (kg/h) of alkanes were quantified using mobile optical Solar Occultation Flux (SOF) measurements.

Furthermore, Mobile White Cell Differential Optical Absorption Spectroscopy (MWDOAS) and Mobile extractive Fourier Transformed Infrared (MeFTIR) techniques were used to measure ground level concentrations of alkanes, BTEX and methane, which allowed us to infer emission fluxes when combined with measured SOF fluxes (see method section for details). In addition, tracer correlation quantification measurements of alkanes and methane, using MeFTIR and N_2O tracer gas release, were performed to obtain emissions from some of the smaller and localized sources. A special study of ammonia emissions from cattle farms using the SOF-technique are also discussed in this report.

Mobile measurements using the FluxSense mobile lab were conducted outside the source site fence-lines along public roads or parking lots. An additional sea-based SOF system was used at sea (Ports of Los Angeles and Long Beach) to assess emissions from fuel islands and off-shore drilling rigs. Background concentrations were subtracted by encircling the sites, when possible, or by checking upwind concentrations, so that only emissions from within the facilities were quantified. Wind data was obtained from a mobile 10 m wind mast or from local met stations, with complementary wind profile information from a Light Detection and Ranging (LIDAR) instrument provided by the SCAQMD. The emission results for each source category are presented as daily and total survey averages and discussed in the context of well-known VOC sources in the SCAB.

SOF is a proven technique that has been developed and applied by FluxSense in over 100 fugitive emission studies around the world. In Europe the SOF technique is considered Best Available Technology (BAT) for measurements of fugitive emission of VOCs from refineries. In Sweden SOF is used together with tracer correlation and optical gas imaging to annually screen all larger refineries and petrochemical industries. The estimated uncertainty for SOF emission measurements is typically ±30 % for total site emissions. The estimated measurement uncertainties have been verified in several (blind and non-blind) controlled source gas release experiments (including the one performed during this project and discussed elsewhere) and in side-by-side measurements with other measurement techniques.

Inter-comparison measurements between the SOF method and other optical techniques such as DIAL (Differential Absorption Lidar) and long-path FTIR were also conducted through side-by-side measurements of emissions from tanks inside a refinery, an intermediate oil treatment plant, and storage tanks near oil wells. The agreement of the SOF technique with other optical remote sensing methods was excellent (i.e. 10-20 %). As part of the SOF, DIAL and long-path FTIR technology comparisons, a blind gas release experiment was also carried out using a controlled source emitting 2 to 25 kg/h of odorless propane at the flat open parking lot of the Anaheim baseball stadium in Anaheim, CA. Here the SOF measurements consistently underestimated true emissions by 35%, but showed excellent correlation for the different release rate configurations (R^2 ~98%). The results of this technology comparison studies are compiled and presented in a separate document.

RESULTS and DISCUSSION

During this project the Fluxsense mobile laboratory surveyed 61 sites, for a total of 451 individual measurement transects. Emissions flux measurements of alkanes using the SOF method were conducted at all sites. Additionally, emission flux measurements of BTEX (using MWDOAS) and of methane (using MeFTIR) were conducted at 28 and 35 sites, respectively. The total measured emission rates from all surveyed locations was 1318 kg/h for alkanes, 68 kg/h for BTEX (12 kg/h of which was Benzene) and 636 kg/h for methane (Table ES 1).

Furthermore, 483 kg/h of alkanes and 301 kg/h of methane were observed from the area in Carson/Wilmington, which contains a mix of multiple sources which individual contribution could not be apportioned due to the lack of publically assessable roads. Finally, a total of 539 kg/h of methane and 245 kg/h of ammonia were detected from 17 cattle farms in Chino Hills. These last emission results, however, are not presented in table ES.1, since their origin is animal husbandry rather than industrial.

Table ES. 1. Summary of FluxSense VOC emission measurements during the 2015 SCAQMD Project-2 survey. Values from Project 1 (Large Refineries) are also included for comparison (see Project 1 report for details).

Source Category (Project-2)	**No. of Units meas.**	**Unit Type**	**No. of Units in the SCAB**	**Tot. sum Alkane Flux [kg/h]**	**Median BTEX Fraction []***	**Median Benzene Fraction []***	**Median CH_4 Fraction []***
Oil & Gas Wells (17 sites)	106	Derricks + small tanks	Over 5000 active wells (DOGGR 2016)	138	0.075	0.012	0.53
Tank Farms, Terminals & Depots (13 sites)	328	Storage tanks	Estimated to 750†	314	0.083	0.010	0.78
Petroleum Treatment Sites & Small Refineries (9 sites)	9	Site	Estimated to 15†	501	0.058	0.014	0.49
Offshore - Facilities & Activities (7 sites)	7	Site	Estimated to 20†	69	n.m.	n.m.	n.m.
Gas Stations (8 sites)	8	Site	Approx. 3140 gasoline - dispensing facilities (SCAQMD, 2016)	10	0.24	0.026	0.25
Other Sources (7 sites)•	7	Site	Unknown	286	n.m.	n.m.	0.38
Sum all Measured Sources and Units (61 Sites)	**465**	Various	-	**1318** [kg/h]	***68**** *[kg/h]*	***12**** *[kg/h]*	***636**** *[kg/h]*
Uncategorized Area Source••	1	Multiple Sites		483	n.m.	n.m.	301
Large Refineries (Project-1)	**6**	Site	-	**1130** [kg/h]	***129**** *[kg/h]*	***18**** *[kg/h]*	***704**** *[kg/h]*

*Fractions are mass relative to alkane mass. **Total flux for BTEX, Benzene and methane are inferred fluxes calculated using median fractions times alkane flux for each category. † Estimation based on visual examination of Google Earth™ maps of the South Coast Air Basin (SCAB). •The category *Other Sources* contains miscellaneous VOC sources. ••The *Uncategorized Area Source* is large industrial area in Carson/Wilmington containing several non-separable sites (refineries, tank farm and terminals). n.m.= not measured.

Due to the large number and type of sources in the SCAB and the limited duration of the study, only a subset of sites has been sampled within each source category. Emissions from the measured sources are relevant for understanding their impact on air-quality in the SCAB only if they are scaled-up to the total number of units in the Region. Scaled-up emissions for all source categories / units in the SCAB were derived by multiplying the average emission rates per unit by the estimated number of units within each category.

Based on our measurements, the average emission rates from an *Oil & Gas Wells* unit (Derrick and/or Storage Tank) was 1.3 kg/h of alkanes, 0.1 kg/h of BTEX (including 0.015 kg/h of

Benzene) and 0.3 kg/h of Methane. The average emission for a typical tank within *Tank Farms, Terminals & Depots* was 0.96 kg/h of alkanes and 0.08 kg BTEX (including 0.01 kg/h of Benzene). For the other source categories, each site was treated as a single emission point except for the *Other Sources*, which were too heterogeneous to separate the individual components and, therefore, were treated as one large area source. Obviously, actual emissions from individual components can vary significantly from the presented averages, depending on product handled, working status (e.g. functioning vs malfunctioning units), emission control equipment, etc.

Figure ES. 1 illustrates the relative contribution of each source category to the estimated total alkane emission flux for the stationary sources investigated in this study (Project-2) and from Project-1 (Six Large Refineries). The overall projected alkane emission from the sources investigated during Projects 1 and 2 was estimated to be approximately 12,000 kg/h. According to our calculations gas stations, oil and gas wells, treatment facilities and other small sources contribute to over 85 % of the total value. It should be noted that emissions from Oil & Gas Wells contribute to more than half of the estimated total.

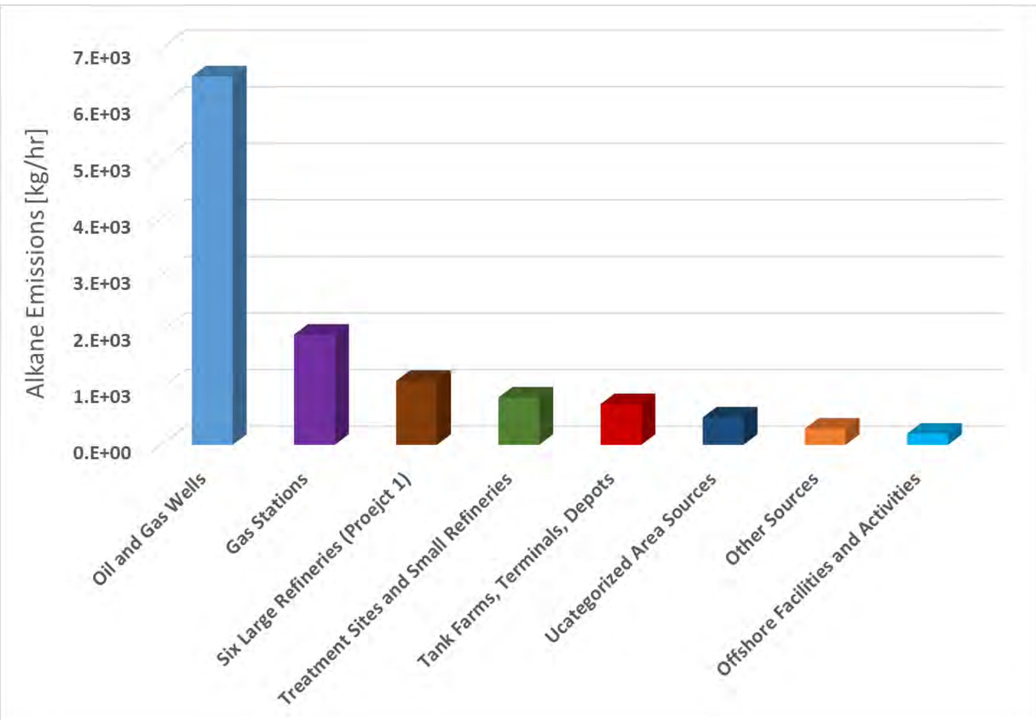

Figure ES. 1. Relative contribution to total **alkane** emissions from the various source categories investigated in Projects 1 and 2. Emission rates for each category were calculated by multiplying the average measured emission per unit by the estimated number of total units. Total alkane emissions are approximately 12,000 kg/h from all included sources.

About 68 kg/h of BTEX (12 kg/h of which was benzene) were directly measured from the subset of sources considered in the project. Scaling-up the observed emissions to account for over 5,000 active oil and gas wells, 3,100 Gas Stations and 750 VOC storage tanks, results in a BTEX load from all measured source categories of around 1,100 kg/h (see Table ES.1). Note that any BTEX emissions from *Offshore Facilities & Activities* and *Other Sources* are excluded here (due to lack of measurements) so the scaled-up value is a conservative value. Despite this limitation, the BTEX emissions from Project-2 sources far surpasses the load from all large refineries in the SCAB (129 kg/h) as measured during Project 1. Considering that a substantial number of sources are located close to residential neighborhoods, these results suggest that further investigation is needed to better quantify the impact of small sources to the total BTEX budget in the Region.

It should be noted that, this scaling-up approach has associated uncertainties because the total number of units has been approximated based on available public information. Additionally, measurements may not be representative for all times of the day and seasons (e.g. gas stations are busier during rush hour traffic, when most of our measurements were made). Total emissions from offshore activities are highly uncertain due to the lack of information on the actual number of fuel barge operations, ship fueling, venting, and other related activities conducted in the Basin. However, at the minimum, this approach provides an indication of the magnitude of all emissions from small stationary sources in the SCAB.

This project also demonstrated the usefulness of conducting mobile survey measurements with optical methods to quickly identify emission and concentration "hot spots" over a large area with multiple emission sources. As such, mobile measurements represent an effective leak detection and repair tool, which can help identify the presence of potential leaks from different parts of a facility. Additionally, mobile measurements provide capability for ground concentration mapping of air toxic pollutants (e.g. BTEX), and as such can be used to assess the health impact of small sources onto neighboring communities.

OUTLOOK

Despite the uncertainties associated with the scaling-up approach adopted here, it is interesting to note that emissions from the six large Refineries (Project-1) only account for a small fraction of the total alkanes and BTEX emissions from stationary sources in the SCAB. Our results suggest that small sources are responsible for the vast majority (over 85 %) of all alkane and BTEX emissions from the stationary sources considered in this study. This finding should motivate further investigation to reconcile measured emission values and estimated emission factors. Additionally, considering the proximity of many of these sources to residential areas, further studies should be conducted to better evaluate potential health impacts on local communities.

The mobile measurement platform and optical methods used in this project allowed for mapping concentrations and measuring fluxes from a large number of sources and source types, and provided very useful information on the relative contribution of small stationary sources to alkane and BTEX emissions in the SCAB. Sources ranged from single oil wells to large tank farms, refineries, and off shore installations. Future studies aimed at improving the emission estimates resulting from this project should include a larger subset of units from all major source categories, and a better characterization of their spatial and temporal variability.

Acronyms, Units and Definitions

Acronyms used in this report

ASOS	Surface Weather Observation Stations
BPD	Barrels per day
BTEX	Sum of Benzene, Toluene, Ethyl Benzene and Xylene
CARB	California Air Resources Board
DOGGR	Division of Oil, Gas & Geothermal Resources, at Department of Conservation CA
DOAS	Differential Optical Absorption Spectroscopy
FTIR	Fourier Transform InfraRed
LDAR	Leak Detection And Repair
LIDAR	Light Detection and Ranging
MWDOAS	Mobile White cell DOAS
MeFTIR	Mobile extractive FTIR
ROG	Reactive Organic Gases
SOF	Solar Occultation Flux
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
VOC	Volatile organic compound, used interchangeably for non-methane VOC

Units

Air temperature	degrees C
Atmospheric Pressure	mbar
Relative Humidity	%
Wind direction	degrees North
Wind speed	m/s
Column	mg/m^2
Concentration	mg/m^3
Flux	kg/h

Unit Conversions

1 lbs = 0.4536 kg
1 kg/h = 52.9 lbs/day
1 bbl = 159 l
1 bbl/day = 5.783 kg/h (crude oil)
1 (short) ton = 907.2 kg
1 kton/year = 104 kg/h
1 klbs/year=0.052 kg/h

Definitions

Alkane or Alkanes are considered to be all non-methane alkane species.

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1 Introduction and Background

Being one of the largest cities in the US and on a global scale, the pollution load to the regional atmosphere of Los Angeles is challenging both for inhabitants getting exposed and for the governing authorities and modelers striving to understand and improve the situation. There are many sources contributing to the air pollution in the South Coast Air Basin (SCAB), both stationary and mobile.

Industrial volatile organic compound (VOC) emissions may contribute to formation of ground level ozone, which is produced through atmospheric chemical reactions of volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of sunlight, often called photo chemical smog. Elevated ozone concentrations are known to reduce crop yields and constitute a public health concern. Larger metropolitan areas in the US, including the SCAB, have trouble meeting ozone standards since anthropogenic sources tend to be concentrated in urban areas, including both mobile and stationary sources. In order to meet current and future more stringent ozone standards in Los Angeles, reductions in VOC emissions are foreseen [Downey et. al. 2015]. VOC emissions from stationary sources, i.e. refineries, storage depots, petrochemical industries etcetera are typically dominated by evaporative losses from storage tanks and process equipment, so-called fugitive emissions. For the SCAB, also fugitive emissions from thousands of active oil and gas wells can contribute to the pollution load. However, actual VOC emissions from distributed sources like oil and gas wells and associated petroleum treatment and intermediate storage installations are uncertain.

Industrial VOC fugitive emissions also contain compounds harmful to human health. For example, aromatic hydrocarbons, including benzene, a known carcinogen, are often found in VOC emissions plumes associated oil and gas extraction. Benzene is also present in gasoline vapors. As a result, a better understanding of sources and magnitudes of fugitive emissions in the SCAB will lead to emission reduction measures leading to potential reduction on health impacts accosted with pollution exposure.

In order to improve our understanding of VOC, NO_2 and SO_2 emissions in the South Coast Air Basin, the South Coast Air Quality Management District (SCAQMD) has promoted and sponsored several measurement projects to study these emissions using optical remote sensing methods. The projects include experimental studies of emissions from refineries, oil depots, treatment facilities, oil & gas wells, gas stations, fuel islands, barges and shipping. In addition, a technology demonstration and validation study was conducted to assess the uncertainties of different optical techniques using side-by-side measurements of real sources and controlled source gas releases.

This report covers the results from the second of three SCAQMD sponsored projects:

- Project 1: Emission Measurements of VOCs, NO_2 and SO_2 from the refineries in the South Coast Air Basin using Solar Occultation Flux and other Optical Remote Sensing Methods
- **Project 2: Using Solar Occultation Flux and other Optical Remote Sensing Methods to measure VOC emissions from a variety of stationary sources in the South Coast Air Basin**
- Project 3: Remote Quantification of Stack Emissions from Marine Vessels in the South Coast Air Basin

For Project 2, measurements of alkanes, BTEX and methane emissions from the following six categories of VOC-sources in the SCAB have been conducted:

1. *Oil & Gas wells* (17 sites, 106 units)
2. *Tank Farms, Terminals & Depots* (14 sites, 343 units)
3. *Petroleum Treatment Sites & Small Refineries* (8 sites)
4. *Offshore Facilities & Activities* (7 sites)
5. *Gas Stations* (8 sites)
6. *Other Sources* (7 sites)

In addition to these categories, a large industrial area in Carson/Wilmington was also studied. Since this area contains multiple sites and a large refinery, the results from this area is reported separately as an "*Uncategorized Area Source*". Another study of emissions from *Cattle Farms* in Chino are also included in this report.

The various result sections in this report further explain the category definitions. We found that the sum of all these sources distributed over the entire SCAB, many of which are located in the immediate proximity of residential areas, is one of the major contributors to VOC-emissions and consequently smog formation in the region.

Emission fluxes of alkanes were measured by mobile optical Solar Occultation Flux (SOF) measurements, for the Cattle Farms ammonia (NH_3) fluxes were also quantified. Emission fluxes of NO_2 and SO_2 were measured using zenith-looking a Differential Optical Absorption Spectrometer (DOAS). The remote sensing techniques were complemented by mobile extractive optical methods, i.e. MeFTIR (Mobile extractive Fourier Transformed Infrared spectrometer) and MWDOAS (Mobile White cell DOAS) to map ground concentrations of alkanes, methane and aromatic VOCs and to calculate inferred fluxes of methane and BTEX when combined with measured SOF fluxes. Direct flux measurements of alkanes and methane, using MeFTIR and tracer gas release (N_2O), were also conducted for some of the smaller and localized sources. A wind-profiling Light Detection and Ranging (LIDAR) instrument supplied by SCAQMD allowed for the continuous measurements of vertical wind profiles. Wind data was also obtained from a mobile 10 m wind mast and from local meteorological stations. Measurements were conducted on land from the FluxSense mobile laboratory, and on water from a research vessel. See Figure 1 for example of measurement setups.

SOF is a proven technique employed by FluxSense in over 100 fugitive emission studies around the world. In Europe the SOF technique is considered one of the Best Available Technology [European Commission 2015] for measurements of fugitive emission of VOCs from refineries; and in Sweden it is used together with tracer correlation and optical gas imaging for annual screening of all larger refineries and petrochemical plants. The estimated uncertainty for the SOF emissions measurements is typically 30 % for the total site emissions. This uncertainty has been calculated from several controlled release experiments (blind and non-blind) and side-by-side measurements with other measurement techniques (also as part of the three SCAQMD projects discussed here).

During this study (Project 2) SOF observations of VOC sources were conducted during 43 measurement days between September 1 and November 15, 2015, resulting in more than 450 transects at 42 different sources. In addition, 23 sources were also measured with MeFTIR combined with tracer gas correlation. Measurements were conducted along publicly accessible roads or parking lots with the FluxSense mobile lab; and from the research vessel within Ports of Los Angeles and Long Beach with a sea-based SOF system, see Figure 1.

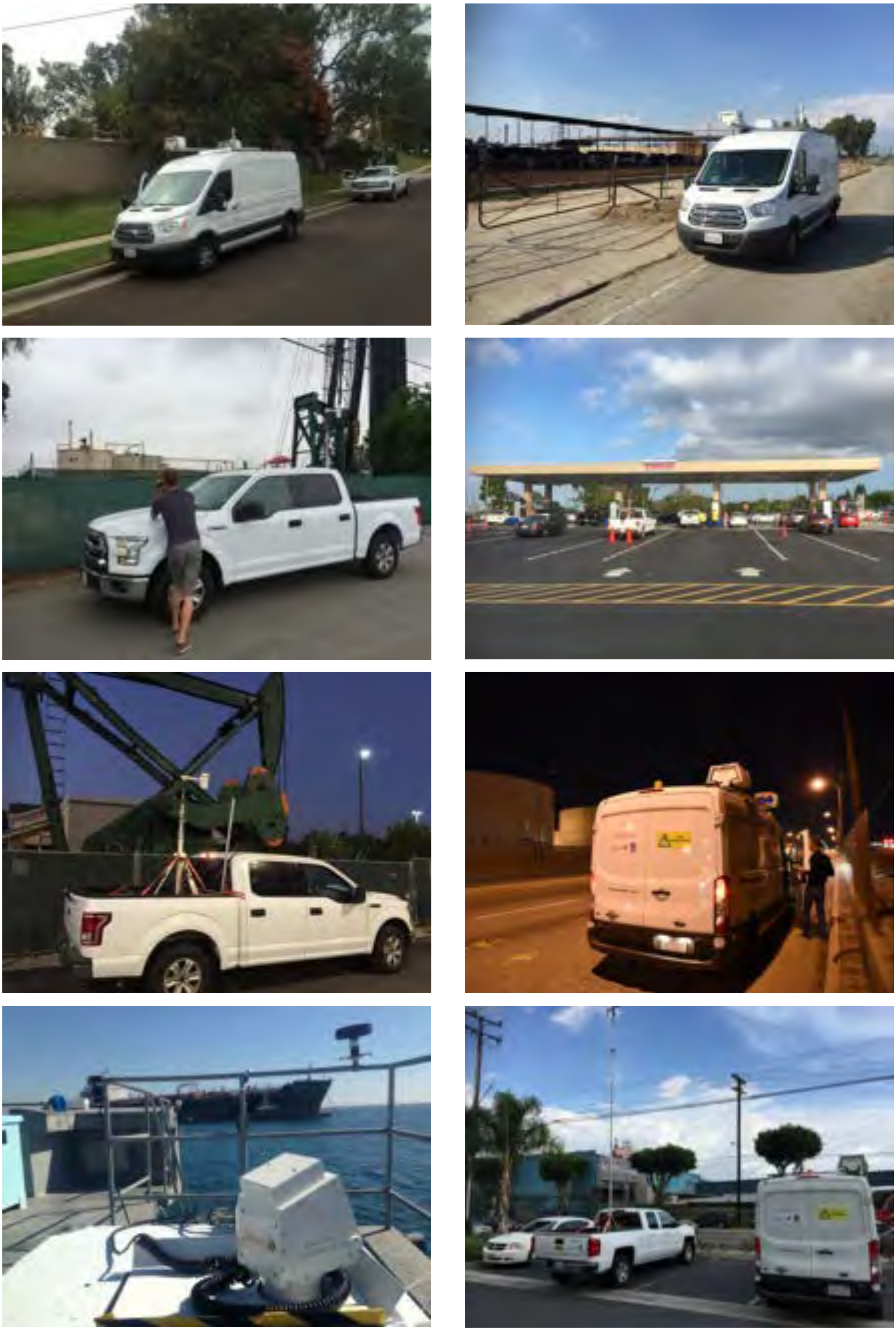

Figure 1. Measurement set-ups and scenarios for various sources during the SCAQMD 2015 survey.

For all sources, background concentrations were subtracted by encircling facilities, so that only emissions from within the facilities were quantified. The results are presented as daily and total survey averages, and discussed in the context of our current understanding of magnitude of VOC sources in the SCAB. Examples of some measurement configurations are presented in Figure 1.

2 Instrumentation and Methods

The FluxSense measurement vehicle or "mobile lab" was equipped with four instruments for gas monitoring during the survey: SOF, SkyDOAS, MeFTIR and MWDOAS. Individual measurement methods are described briefly in the subsections below. SOF and SkyDOAS both measure gas columns through the atmosphere by means of light absorption. SOF utilizes infrared light from the direct sun whereas SkyDOAS measure scattered ultraviolet light from the sky. Note that SkyDOAS was only used for Project-1 and Project-3 and is, henceforth, not described in this report. MeFTIR and MWDOAS both measure ground level concentrations of alkanes and BTEX respectively. Accurate wind data is necessary in order to compute emission fluxes. Wind information for the survey was derived from several different sources as described in detail in Section 2.4. A wind LIDAR was used to measure vertical profiles of wind speed and wind direction from 50-1000 m height. The LIDAR data was combined with data from several wind masts from fixed met network- and mobile stations. Figure 2 gives a general overview of the measurement setup and the data flow and pictures of the FluxSense mobile lab is found in Figure 3.

In order to derive final emission flux estimates, the GPS-tagged gas column measurements by SOF and SkyDOAS are combined with wind data and integrated across plume transects at the various source locations. Gas mass ratio measurements by MeFTIR and MWDOAS are then used to infer emission estimates also for methane and BTEX (which can't be measured directly by SOF and SkyDOAS). Occasionally, tracer gas correlation was used at localized sources to measure emissions directly with MeFTIR. Note that SkyDOAS was not used within the present project, but in two the other projects covering refinery and ship emissions.

During the second half of the survey, a smaller SOF instrument was also deployed. This SOF instrument was operated for seven measurement days on a research vessel for offshore measurements between October 13 and October 26, 2015; and for six measurement days between October 29 and November 9, 2015 from the bed of a pick-up truck. Table 1 summarizes the main features and characteristics of all measurement techniques used for this study.

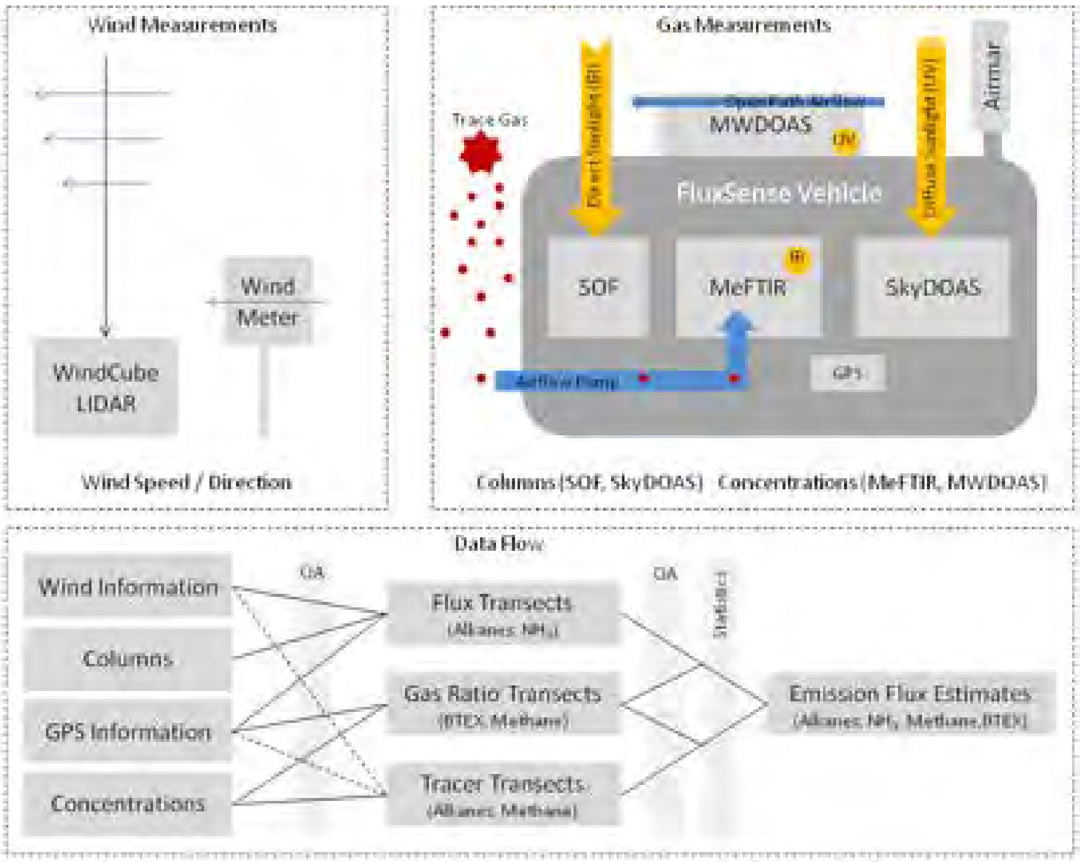

Figure 2. Overview of the FluxSense mobile lab main instruments; SOF, MeFTIR, MWDOAS and SkyDOAS (upper right panel) and wind measurements (upper left panel) and simplified data flow diagram (lower panel). SOF and SkyDOAS are column integrating passive techniques using the Sun as the light source while MeFTIR and SkyDOAS sample local air concentrations using active internal light sources. The data flow describes what information that goes into the flux emission estimates. Direct flux emissions are given from measured columns (SOF and SkyDOAS) of alkanes, SO_2 and NO_2, while inferred fluxes are calculated via gas concentration ratios (MeFTIR and MWDOAS) of BTEX and CH_4. See section 3.2 for principal equations. All emission flux estimates are based on statistical analysis of measured data. Q.C. = Quality Control, S.A.= Statistical Analysis (see Appendix for details). Note that SkyDOAS was not used within Project 2 (this report), but in the other projects covering refinery and ship emissions.

Figure 3. Internal and external view of the FluxSense mobile lab.

Table 1.Summary of FluxSense gas measurement techniques. *For typical wind conditions at an optimal distance from the source. SkyDOAS not used in this project.

Method	SOF	Sky DOAS	MeFTIR	MWDOAS
Compounds	**Alkanes**: (C_nH_{2n+2}) **Alkenes:**C_2H_4, C_3H_6 **NH_3**	SO_2 NO_2,	**CH_4** **Alkanes:** (C_nH_{2n+2}) **Alkenes:** C_2H_4, C_3H_6 **NH_3** **N_2O** (tracer)	**BTEX**
Detection limit Column	0.1-5 mg/m^2	0.1-5 mg/m^2	1-10 ppbv	0.5-3 ppbv
Detection limit Flux*	0.2-1 kg/h	1 kg/h	0.2-2 kg/h	1-2 kg/h
Wind Speed Tolerance	1.5-12 m/s	1.5-12 m/s		
Sampling Time Resolution	1-5 s	1-5 s	5-15 s	8-10 s
Measured Quantity [unit]	Integrated vertical column mass [mg/m^2]	Integrated vertical column mass [mg/m^2]	Mass concentration at Vehicle height [mg/m^3]	Concentration at Vehicle height [mg/m^3]
Inferred Quantity [unit]	Mass Flux [kg/h]	Mass Flux [kg/h]	1) Alkane ratio of ground plume combined with SOF gives mass flux [kg/h] and plume height information [m] 2) Alkane and CH_4 flux [kg/h] via tracer release	Combined with MeFTIR and SOF gives Mass Flux [kg/h]
Complementary data	Vehicle GPS-coordinates, Plume wind speed and direction	Vehicle GPS-coordinates, Plume wind speed and direction	Vehicle GPS-coordinates Plume wind direction	Vehicle GPS-coordinates, Plume wind direction

2.1 The SOF method

The SOF method [Mellqvist 1999, 2008a, 2008b, 2009, 2010; Kihlman 2005a; Johansson 2014] is based on the recording of broadband infrared spectra of the sun with a Fourier transform infrared spectrometer (FTIR) that is connected to a solar tracker. The latter is a telescope that tracks the sun and reflects the light into the spectrometer independent of the orientation of the vehicle. Using multivariate optimization, it is possible from these solar spectra to retrieve the path-integrated concentrations (referred to as column concentrations), in the unit mg/m^2, of various species between the sun and the spectrometer. The system used in this project consists of a custom built solar tracker, transfer optics and a Bruker IRCube FTIR spectrometer with a spectral resolution of 0.5 cm^{-1}, equipped with a dual InSb (Indium Antimonide) / MCT (Mercury Cadmium Telluride) detector. A reference spectrum is taken outside the plume so that atmospheric background concentrations are removed. This means that all measured SOF columns are analyzed relative to the background column concentrations.

The system is installed in a measurement vehicle which allows consecutive column concentration measurements to be performed while driving. The flux of a species in a plume from an industry is measured by collecting spectra while driving the vehicle so that the light path from the sun to the instrument gradually cuts through the whole plume, preferably as orthogonally as possible to the wind direction, see Figure 4.

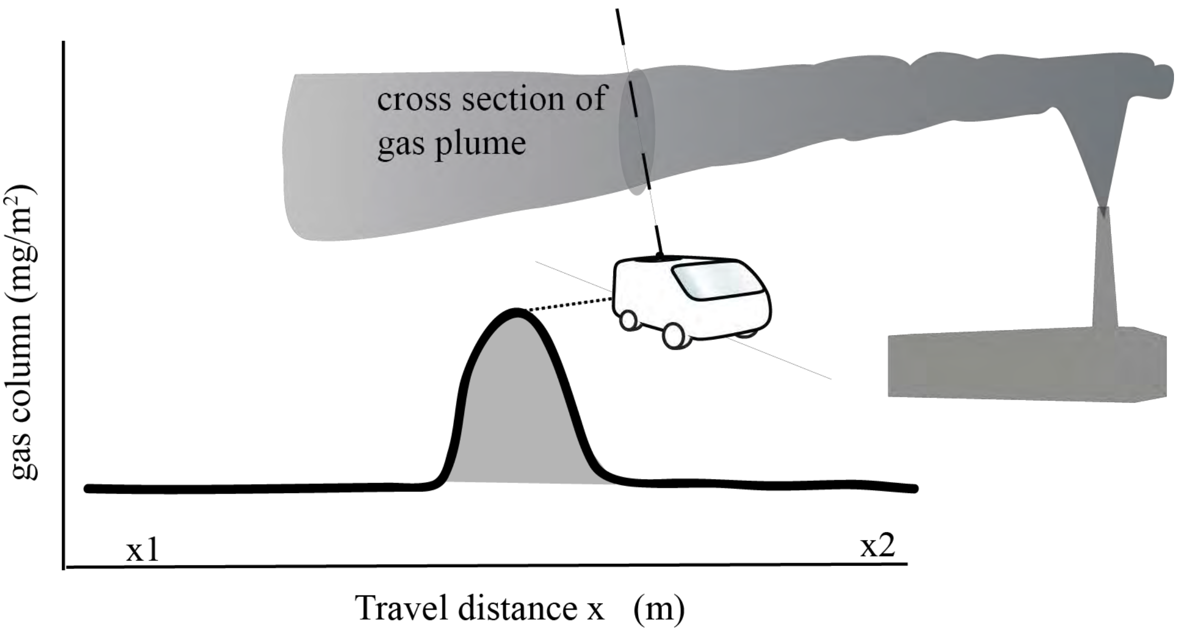

Figure 4. Schematic of the SOF measurement where the vehicle is driven across the prevailing wind so that the solar beam cuts through the emission plume while the sun is locked into the FTIR spectrometer by the solar tracking device on the roof. The VOC mass (or other compound of interest) is integrated through the plume cross section. See section 3.2 for complete equations.

For each spectrum a column concentration of the species is retrieved using custom software (QESOF, i.e. *Quantitative evaluation of SOF*) [Kihlman 2005b]. These column concentrations, together with positions recorded with a GPS (Global Positioning System) receiver and the solar angle calculated from the time of the measurements, are used to calculate the area integrated column of the species in the intersection area between the plume and the light path. The flux of the species is then obtained by multiplying this area integrated concentration with the orthogonal wind speed vector component.

The IR spectra recorded by the SOF instrument are analyzed in QESOF by fitting a set of spectra from the HITRAN infrared database [Rothman 2003] and the PNL database [Sharpe 2004] in a least-squares fitting procedure. Calibration data from the HITRAN database is used to simulate absorption spectra for atmospheric background compounds present in the atmosphere with high enough abundance to have detectable absorption peaks in the wavelength region used by SOF. Spectra, including water vapor, carbon dioxide and methane, are calibrated at the actual pressure and temperature and degraded to the instrumental resolution of the measurements. The same approach is applied for several retrieval codes for high resolution solar spectroscopy developed within Network for the Detection of Atmospheric Composition Change (NDACC) [Rinsland 1991; Griffith 1996] and QESOF has been tested against these with good agreement, better than 3%. For the retrievals, high resolution spectra of ethylene, propene, propane, n-butane and n-octane were obtained from the PNL (Pacific Northwest Laboratory) database and these are degraded to the spectral resolution of the instrument by convolution with the instrument line shape. The uncertainty in the absorption strength of the calibration spectra is about 3.5% for all five species.

In this project, the SOF method was used to measure VOCs in two different modes. Most VOCs with C-H-bonds absorb strongly in the 3.3-3.7 µm (2700-3005 cm^{-1}) spectral region. This region is mainly used for alkane measurements using a spectral resolution of 8 cm^{-1}. Alkenes (including ethylene and propylene) and ammonia are instead measured in the spectral region between 910 and 1000 cm^{-1} using a spectral resolution of 0.5 cm^{-1}. In the alkane mode – the IR light absorption is essentially sensitive to the total alkane mass (number of alkane C-H bonds) present in the plume. The absorption structures (cross sections) for the various alkane compounds are rather similar, with the absorption strength scaling to the mass of the alkane species. Hence, the actual mix of alkanes in the plume does not affect the retrieved total alkane mass flux much, although only cross sections from a subset of all alkanes (propane, n-butane and octane) are fitted in the spectral analysis. Typically, the rare event of significant absorption from other species in the plume shows up as elevated residuals and is further investigated in the re-analysis. For the alkene mode the specificity of the measurements is good, since the absorption of different species is rather unique in this so called “fingerprint region” and absorption features are often sharp and well separable from each other at 0.5 cm^{-1} resolution.

2.2 Mobile extractive FTIR (MeFTIR)

Mobile Extractive FTIR (MeFTIR) [Galle 2001, Börjesson 2009] in combination with tracers has been used to quantify VOC emissions from refinery and petrochemical sources in Europe and in the U.S. alkanes and alkenes are typically measured, but also methane and other climate gases can be retrieved. MeFTIR is an optical technique capable of monitoring gas concentrations at ppb-sensitivity in mobile field operations. It is used both independently for concentration mapping and flux measurements, but often combined together with simultaneous SOF flux measurements to provide more detailed VOC speciation of plumes and for plume height assessments [Johansson et. al. 2013a]. The plume height can be estimated by dividing measured columns (mg/m^2) with ground concentrations (mg/m^3), assuming that the plume is evenly distributed up to the plume height (and zero above).

The MeFTIR system contains a mid-infrared spectrometer with medium resolution (0.5 cm^{-1}). It utilizes an internal glow bar as an infrared radiation source, and by customized optics this light is transmitted through an optical multi-pass measurement cell with selectable path-length of 9.6-107.2 meters. The system is mounted on a vibration dampening platform to allow for real time plume mapping from a mobile platform, such as a vehicle or boat, see Figure 5.

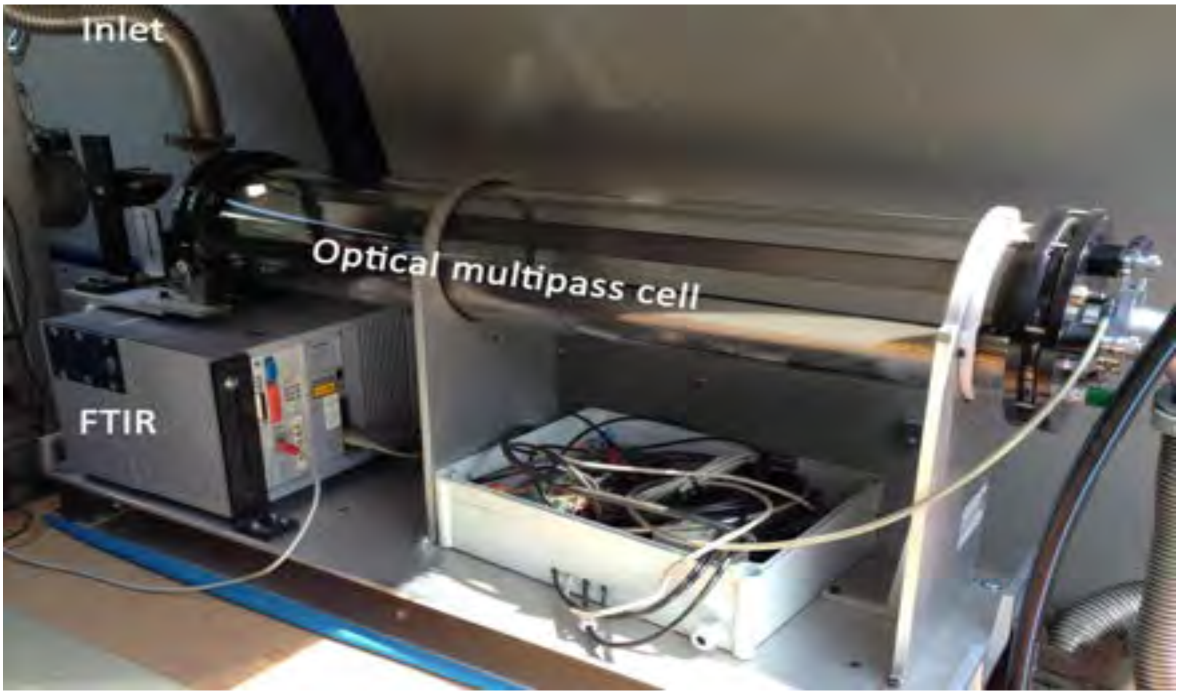

Figure 5. The MeFTIR instrumentation consisting of a Bruker FTIR spectrometer connected to an optical multi-pass cell.

The concentration in the spectra is analyzed in real time by fitting a set of calibrated spectra from the Hitran infrared database [Rothman 2003] and the PNL database [Sharpe 2004] in a least-squares fitting procedure. Compounds being analyzed include ethylene, propylene, total alkane mass (based on fitting cross sections of ethane, propane, n-butane, i-pentane, n-octane), water, methane, CO, CO_2 and N_2O. The analysis routines are very similar to the ones for SOF, but less complex because strong absorption by atmospheric trace gases (water, methane, CO_2) has less consequence at the shorter path length in the MeFTIR measurement cell.

The MeFTIR tracer approach has been tested in a so called gas release "blind test" together with other techniques in U.S. [EREF 2011]. In that test, methane was released from an area-distributed source in four different configurations and flow rates ranging from 1.1-3.3 g/s. At a downwind distance of 400 meters MeFTIR retrieved the fluxes within 6% in 3 cases and 19% in the fourth. This is consistent with other validation experiments, showing a flux estimate accuracy of better than 20%. Concentration measurement by FTIR is a widely used procedure, and the main uncertainties are associated with the absorption cross sections (typically < 3.5%) and spectral retrieval, with an aggregate uncertainty better than 10% in the analysis. Concentrations are monitored in real time in order to detect emission plumes and to judge whether any interfering sources are being sampled. Unwanted signals from local traffic exhaust or from the measurement vehicle itself could be filtered out by looking at the carbon monoxide (typical exhaust compound) concentrations. A stationary source is, on the contrary to any local traffic plumes, characterized by recurrent downwind plumes. Transient and non-repeatable observations are therefore excluded from the results. Furthermore, measurements of ambient concentrations of methane and carbon dioxide (with known atmospheric concentrations) are used for consistency check.

2.3 Mobile White Cell DOAS (MWDOAS)

The ground level mass concentration of Benzene, Toluene, Ethylbenzene, meta- and para-Xylene (BTEX) was measured using a mobile real-time system: Mobile White cell DOAS (MWDOAS). The Mobile White cell DOAS system consists of an open, 2.5 m long optical White cell that is mounted on the roof of the measurement vehicle (see Figure 6). By multiple reflections in the White cell mirror system an overall path length of 210 m is obtained, resulting in low detection limits (ppb). The light from the internal lamp is transmitted through the White cell and then analyzed in a DOAS spectrometer, using the UV wavelength region 255 - 285 nm.

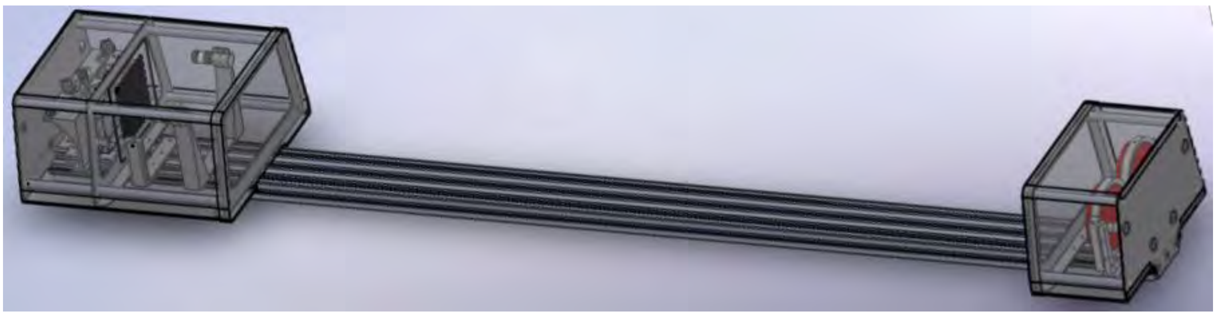

Figure 6. The open path MWDOAS cell having an overall optical path-length of 210 m.

A measurement begins by acquiring a reference spectrum outside the plume, usually upwind of the facility. Spectra are then sampled and averaged continuously while driving through emission plumes. The averaging time is set to around 8 seconds in order to achieve acceptable SNR (see below). This is the lower limit of the temporal sampling between independent measurements, but the spatial sampling is also dependent by the vehicle's velocity. A typical driving speed for MWDOAS measurements is 10-20 km/h for sufficient plume sampling.

The spectra are geo-tagged and evaluated online using the standard DOAS technique, giving information of plume locations and constituents. Cross-sections included in the evaluation are tabulated in Table 2.

Table 2. The UV-cross-sections used in the evaluation of the MWDOAS spectra.

Chemical compound	Origin of reference spectrum
O_3	[Burrows 1999]
SO_2	[Bogumil 2003]
O_2	[Bogumil 2003]
Toluene	[Fally 2009]
Benzene	[Etzkorn 1999]
1,3,5-Trimethylbenzene	[Etzkorn 1999]
1,2,4-Trimethylbenzene	[Etzkorn 1999]
Styrene	[Etzkorn 1999]
Phenol	[Etzkorn 1999]
p-Xylene	[Etzkorn 1999]
m-Xylene	[Etzkorn 1999]
Ethylbenzene	[Etzkorn 1999]

The MWDOAS data is later post evaluated and merged with the corresponding MeFTIR data to produce a plume specific BTEX/Alkane mass ratio. The mass ratio of BTEX/Alkanes is then used to calculate the aromatic flux from individual sub areas where alkane fluxes have been measured by SOF, assuming they have the same source. Specific area plumes are ideally probed at several times, and an overall average of all plume transect BTEX/Alkane ratios is then made. The method requires in situ access to the plume of the studied source, and as instrumentation typically are mounted on a truck, highly elevated sources with a strong plume lift like hot flares, chimneys and high process towers will not be possible to survey at close distance.

The MWDOAS technique has been validated in various surveys by comparison with canister samples acquired at several different locations and which were subsequently analyzed by gas chromatography (GC-FID). The validation shows that the result from MWDOAS lies well within 10% of the result of the certified canister results for BTEX. Due to an absorption cross-section too weak to be used with reliability in the MWDOAS analysis, the ortho isomer of the Xylene has been omitted in this comparison. When total Xylene is presented in the present survey, the sum of m-and p-Xylenes from the MWDOAS measurement is multiplied by 1.32. This number comes from a ratio comparison of Xylene isomers in 49 canister samples analyzed by GC/FID and taken from eight refineries and tank parks from two countries. The standard deviation in this comparison was 0.07 and adds a 4.5% uncertainty to the total Xylene concentration. Hence, the Xylene concentration from MWDOAS is defined as the sum of the measured m- and p-isomers and the inferred o-isomer.

The MWDOAS system has been used in previous campaigns in USA during 2013 with good results. During the 2013 DISCOVER-AQ campaign [Johansson, 2013b] in Houston, Texas, the system was run in parallel to a mobile Proton Transfer Mass spectrometer (PTrMS) lab as a validation check. The results of Benzene, Toluene and Styrene was compared and showed good agreement, with the PTrMS showing slightly elevated Benzene concentrations compared to the MWDOAS. The sensitivity of MWDOAS is better than 1 ppb for Benzene, better than 3 ppb for Toluene, Ethylbenzene and m-Xylene and as good as 0.5 ppb for p-Xylene.

Since the distribution of the BTEX constituents varies with source we will also present the Benzene to alkane ratio to facilitate the calculation of Benzene flux and identify specific Benzene sources.

Unwanted BTEX signals from local traffic exhausts are generally only significant in congestions (at traffic lights etc.) or in confined spaces, e.g. tunnels. Apart from this, large emitters are also occasionally seen elsewhere. They are generally recognized, partly by their typical gasoline composition signature and partly by their transient nature. A stationary BTEX source is, on the other hand, characterized by recurrent downwind plumes. Transient and non-repeatable BTEX observations are therefore excluded from the result. Note that all concentrations are above the reference/background.

2.4 Wind Measurements and Auxiliary Data

Wind LIDAR

An infrared 3D wind LIDAR provided by SCAQMD was used to measure vertical wind profiles of wind speed and direction. The Leosphere WindCube 100S LIDAR provided wind profiles in the vertical range of 50 m to approximately 1000 m above ground, with 25 m vertical resolution, and wind speed accuracy of 0.5 m/s. The system records 1s data, but 10 minute averages were used for flux calculations in this study. The principle of detection is based on the Doppler shift of the infrared pulse that the instrument sends out and retrieves. Numerous validation surveys attesting the accuracy of the WindCube LIDARs are publically available at www.leosphere.com.

Figure 7. The WindCube 100S (Leosphere) LIDAR used for wind profile measurements in this project.

Wind Masts

Meteorological parameters were measured at selected sites using a portable 3-10 m mast. This mast was equipped with a calibrated RM Young 05108 “prop and vane” anemometer and a Campbell Scientific CR5000 data-logger, see Figure 7. An additional wind mast with a Gill Wind Sonic ultrasonic sensor was occasionally used to measure wind speed and direction.

The weather mast was installed at an open location near the measured source and with un-obstructed fetch for wind directions that was used for SOF measurements. The sensor was adjusted to point towards magnetic north but compensated to true north in the post-processing. Wind speed information from the 10-m mast was the main source of wind information for the sources at near distance since plumes are found to be closer to the ground as compared to large refinery plumes. See section 3.4 for a thorough wind analysis.

Figure 8. The FluxSense mobile wind mast used in the 2015 SCAQMD survey with an RM Young anemometer mounted on top. The mast could be erected from 3 to 10 m.

Airmar (Mobile Weather Station)

An Airmar WeatherStation (200 WX) sensor was installed on the roof of the measurement vehicle to complement the other wind measurements and give local ground winds at the vehicle. An additional Airmar Weather Station was also mounted on the top of the research vessel during offshore measurements.

The wind information from the car-based Airmar was not used for flux calculation since the wind field at street level can be heavily disturbed and turbulent. The Airmar was only used as a real-time aid to keep track of the plume directions when making the gas emission measurements. The vessel-based Airmar, on the other hand, was used for flux calculations.

The Airmar provides wind speed and direction relative to true north (compensating for vehicle position), as well as air temperature, pressure and relative humidity. It also provides GPS positions that may be used as a backup for the other GPS-antenna.

GPS

The FluxSense vehicle is equipped with two standard USB GPS-L1 receivers (GlobalSat BU-353S4) hooked up to the SOF and MWDOAS-computers. They are placed horizontally by the windscreen and at the sun-roof for optimal reception. The receivers give the position at a rate of 1 Hz.

3 Measurement Methodology

Typically, the main instruments in the FluxSense mobile lab are operated during favorable meteorological conditions. SOF and Sky-DOAS are mainly used during solar/daytime measurements and MWDOAS and MeFTIR for gas ratio measurements during day or cloudy/nighttime conditions. Plume height calculations are dependent on simultaneous SOF and MeFTIR measurements of alkanes, so MeFTIR was typically running during solar/daytime conditions, when feasible. MWDOAS and SkyDOAS were sharing the same spectrometer in this survey. Hence, time sharing between two different techniques was necessary. In addition to the gas mass ratio measurements by MWDOAS and MeFTIR, canister samples were taken when measuring selected plumes for VOC speciation and complimentary data.

SOF was the primary flux emission measurement technique for this study, but some sources with very small footprint were measured using MeFTIR and tracer gas release. This approach was found to be more favorable for small localized sources and was used for all gas stations and for a few wells- and petroleum treatment sites.

3.1 Survey Setup

The project objective was to quantify the gas emissions of alkanes (non-methane), BTEX and methane from a variety of stationary sources distributed in the SCAB, see Figure 9, in order to obtain a better understanding of the overall VOC load to the Los Angeles atmosphere. For some “organic” sources, such as cattle farms, NH_3 fluxes were also measured. In addition, emissions from “special events” such as flaring and fracking were monitored during the study. The observations were mainly done by fence-line measurements along accessible roads outside the facilities using SOF but also with MeFTIR using N_2O as tracer gas when feasible. In this case the tracer gas was released as close to the source as possible. Furthermore, ground concentration measurements were carried out with mobile MWDOAS and MeFTIR instruments to infer emissions of methane, BTEX and specifically benzene.

The gas measurements were combined with wind data, primarily from a mobile 10 m wind mast but also from adjacent stationary meteorological stations, to calculate fluxes and identify sources. The locations of the small sources are shown as colored flags in Figure 9. Area sources are also noted as colored regions. Locations of meteorological stations are shown in Figure 10. Note that individual sources vary in physical size, number of units (e.g. number of tanks, wells, derricks, etc.) or capacity, but each category represents an ensemble of typical sources.

To be able to get a good selection of sources during the time-frame of the project, several sources were covered during each measurement day. For statistical reasons, the aim was to get more than one transect of each source for each time. Some of the sources, however, were discovered accidentally while passing by and, therefore, have less statistical significance. Furthermore, many of the sources were revisited on several days in order to understand the day-to-day variability of emissions.

Plume separation from different sources were performed by encircling the source and subtracting incoming plumes from the outgoing. When encircling the source was not possible (e.g. lack of accessible roads), relevant upwind measurement transects were instead made in close proximity in space and time.

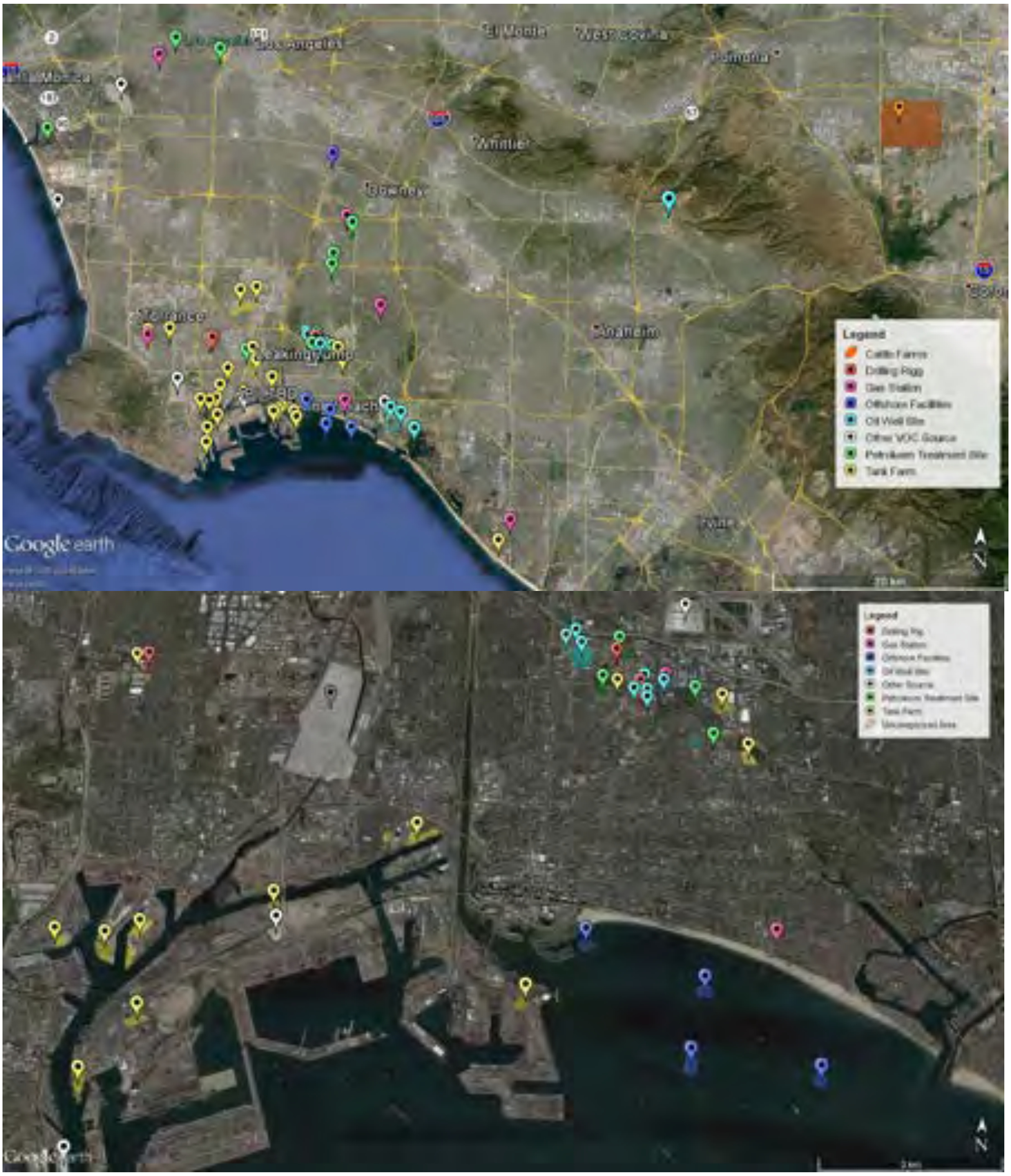

Figure 9. Overview of the measured small sources in the SCAQMD survey 2015. Entire Los Angeles basin (top) and zoomed in at Long Beach/Signal Hill (bottom). Map from Google Earth © 2016.

Observations of sources were made during 43 measurement days between September 1 and November 11, 2015, resulting in more than 450 successful transects of 62 different sources. Of these measurement objects, 42 were made with SOF and 23 sources with MeFTIR + tracer correlation. The number of successful measurements varied substantially from day to day and from source to source depending on weather conditions, local measurement conditions (accessibility, state of the roads, obstacles etc.) and time sharing between different projects, objects and instruments.

Statistical estimates of the flux emissions (kg/h) from the various sources were computed for each measurement day and for the entire survey. This data is compared within and between categories and to the measured emissions from the six largest refineries (Project-1). Extreme events area also identified specifically in the report.

All sources are categorized and assigned names based on the type of source, followed by the closest road intersection and by location of the source relative to that intersection. Table 3 provides a complete list of sources characterized during this project.

Table 3. Overview of all measured sources in SCAQMD 2015, Project-2. Latitude and longitude links refer to Google Maps. Source are identified as following: Source type_Closest road intersection,_Direction to the source from the intersection. Number of units noted, where applicable.

Source Name (Intersection) and Category	No of Units	Latitude, Longitude
Oil & Gas Wells (Derricks, Tanks and Drilling Riggs)	Derricks and Tanks	
Wells_AtlanticAve_ESpringSt_SE	31	33.810703, -118.182837
Wells_WalnutAve_CrescentHeightsSt_NE*	5	33.803406,-118.169738
Wells_AtlanticAve_ESpringSt_SW	16	33.811014, -118.185985
Wells_MarbellaAve_ESepulvedaBlvd_SSW	7	33.808440, -118.175760
Wells_OrangeAve_E28thSt_NW	1	33.806331, -118.272040
Wells_RoseAve_CrestonAve_SW	4	33.799705, -118.169604
Wells_TempleAve_E21stSt_SW	17	33.794458, -118.160333
Wells_ValenciaAve_ELambertRd_NW	8	33.925451, -117.851639
Wells_WalnutSt_W236thSt_SW	4	33.811055, -118.312400
Wells_AtlanticAve_ESpringSt_NW	1	33.812020, -118.184205
Wells_RoseAve_EWillowSt_S	1	33.803759, -118.170132
Wells_GardenaAve_EBurnettSt_NW	2	33.801084, -118.169583
Wells_NOrizabz_E20th_SE	1	33.793222, -118.156420
Wells_PuertoNatalesDr_VinaDelMarAve_SE	2	33.882638, -117.839950
Wells_RoseAve_CrestonAve_SW	4	33.799682, -118.169546
Wells_JeffersonBlvd_BudlongAve_W	1	34.026293, -118.296273
Wells_TonnerCanyonRd_W	1	33.932614, -117.860209
	Sum 106	
Tank Farms, Terminals & Depots	Tanks	
TankFarm_HarbourPlaza_SHarborScenicDr_SE	28	33.750290, -118.192666
TankFarm_PierASt_PierAPl_SW	24	33.756409, -118.272007
TankFarm_RedondoAve_EPacificCoastHwy_NE	24	33.791695, -118.149814
TankFarm_SHenryFordAve_DockSt_NW	54	33.763783, -118.240870
TankFarm_SanClementeAve_SLaPalomaAve_W	43	33.758410, -118.265735
TankFarm_RedondoAve_EWillowSt_SW	24	33.801228, -118.154506
TankFarm_NParamountBlvd_ESouthSt_NW	30	33.865179, -118.163399
TankFarm_WEdisonWay_LuggerWay_SW	10	33.775727, -118.220775
TankFarm_WarfSt_SeasideAve_SW	19	33.735570, -118.272952
TankFarm_FerrySt_PilchardSt_W	7	33.745416, -118.264016
TankFarm_OrangeAve_E25thSt_NE*	12	33.802769, -118.175764
TankFarm_EdisonAve_PierBSt_SE	35	33.776690, -118.213158
TankFarm_JohnSGibsonBlvd_E	18	33.756741, -118.281578
	Sum 328	

Petroleum Treatment Sites & Small Refineries		
TreatmentSite_WilmingtonAve_EDelAmoBlvd_SE	n.a.	33.845094, -118.232228
TreatmentSite_TempelAve_CombellackDr_SW	n.a.	33.801815, -118.159817
TreatmentSite_StJamesPark_W23rdSt_SE	n.a.	34.032084, -118.278116
TreatmentSite_OrangeAve_ESpringSt_SE	n.a.	33.810722, -118.174118
TreatmentSite_LewisAve_EWillowSt_SE	n.a.	33.803451, -118.178492
TreatmentSite_GreenwichCir_RumsonSt_E	n.a.	33.880558, -117.840767
TreatmentSite_SMainSt_WSepulvedaBlvd_SSE	n.a.	33.804931, -118.274477
Refinery_LakewoodBlvd_SomersetBlvd_NW	n.a.	33.898365, -118.147114
Refinery_ NParamountBlvd_EArtesiaBlvd_SW	n.a.	33.873691, -118.162155
Offshore Facilities & Activities		
OffShore_FuelIsland_Chaffet	n.a.	33.739580, -118.138958
OffShore_FuelIsland_Freeman	n.a.	33.741482, -118.162368
OffShore_FuelIsland_Grissom	n.a.	33.759425, -118.181594
OffShore_FuelIsland_White	n.a.	33.752502, -118.159479
OffShore_FuelBarges_PortLA	n.a.	variable
OffShore_ShipVenting	n.a.	variable
OffShore_ShipFueling	n.a.	variable
Other Sources		
FuelSupply_SWesternAve_PalosVerdesDrN_SE	n.a.	33.773836, -118.301677
Seaside_45thSt_VistaDelMarBlvd	n.a.	33.907980, -118.423985
Industry_area_CherryAve_EWardlowRd_SE	n.a.	33.816891, -118.162508
PowerPlant_TerminalIslandFwy_SeasideFwy_NW	n.a.	33.759775, -118.240113
OtherSite_AlamedaSt_PacificCoastHighwaySt_SO	n.a.	33.789433, -118.243065
Old_TankFarm_SignalSt_E22St_SE	n.a.	33.724073, -118.273188
Source_Valencie_Lambert_Brea_olinda	n.a.	33.924553, -117.848440
Gas Stations	Average # of fueling cars at gas station	
GasStation_CherryAve_EWillowSt_SE	8.1	33.804102, -118.165788
GasStation_DowneyAve_RosecransAve_SE	2.9	33.903581, -118.151222
GasStation_GoldenwestSt_YorktownAve_NE	2.2	33.679586, -118.005702
GasStation_BeachBlvd_AdamsAve_NE	2	33.672554, -117.989038
GasStation_CrenshawBlvd_SkyparkDr_NW	15	33.805578, -118.332870
GasStation_CrenshawBlvd_WJeffersonBlvd_NW	2.6	34.025814, -118.335617
GasStation_EOceanBlvd_ELivingstonDr_E	1	33.760373, -118.145459
GasStation_WoodruffAve_HarveyWay_SE	2.9	33.834452, -118.116030
Uncategorized Area Source		
TankFarm&Refineries_Sepulveda_Alameda_SE	n.a.	33.802607, -118.233229

3.2 Principal Equations

This report includes three different techniques to measure emission mass fluxes as specified below. The primary method in this project is the direct flux measurements of alkanes from SOF. Secondary method (for small and confined sources) is tracer gas measurements from MeFTIR using N_2O as tracer gas. BTEX and methane fluxes are calculated using inferred fluxes from MWDOAS/MeFTIR gas mass ratios.

3.2.1 DIRECT FLUX MEASUREMENTS:

The emission mass flux (*Q*) of species (*j*) measured by SOF for a single transect (*T*) across the plume (*P*) along path (*l*) can be expressed by the following integral (Si-units in gray brackets):

$$Q_T^j[\mathrm{kg/s}] = \bar{v}_T[\mathrm{m/s}] \cdot \int_P C_l^j[\mathrm{kg/m^2}] \cdot \cos(\theta_l) \cdot \sin(\alpha_l)\ dl\ [\mathrm{m}]$$

Where,

$\bar{v}_T$ = the average wind speed at plume height for the transect,
C_l^j = the measured slant column densities for the species *j* as measured by SOF or SkyDOAS,
θ_l = the angles of the light path from zenith ($\cos(\theta_l)$ gives vertical columns),
α_l = the angles between the wind directions and driving directions
dl = the driving distance across the plume

Note that SOF and SkyDOAS have different light paths, where the SkyDOAS telescope is always looking in the zenith direction while the SOF solar tracker is pointing toward the Sun. Hence, the measured SOF slant column densities will vary with latitude, season and time of day.

To isolate emissions from a specific source, the incoming/upwind background flux must be either insignificant or subtracted. If the source is encircled or "boxed", the integral along *l* is a closed loop and the flux calculations are done with sign. This is taken care of by the FluxSense software.

3.2.2 INFERRED FLUX MEASUREMENTS:

Inferred flux is computed using a combination of SOF and MeFTIR/MWDOAS measurements. The inferred mass flux ($\hat{Q}^i$) for species (*i*) are calculated from MeFTIR and/or MWDOAS ground level gas ratios integrated over the plume (*P*) along path (*l*) are given by (Si-units in gray brackets):

$$\hat{Q}^i[\mathrm{kg/s}] = \bar{Q}^j[\mathrm{kg/s}] \cdot \frac{1}{k}\sum_k \frac{\int_P N_l^i[\mathrm{kg/m^3}]\ dl[\mathrm{m}]}{\int_P N_l^j[\mathrm{kg/m^3}]\ dl[\mathrm{m}]}$$

Where,

$\bar{Q}^j$ = the average flux of species *j* from multiple transects as measured by SOF,
N_l^i = the number density concentrations of species *i* as measured by MWDOAS or MeFTIR,
N_l^j = the number density concentrations of species *j* as measured by MeFTIR,
k = the number of gas ratio measurements

Note that the inferred flux calculation operates on average values since simultaneous SOF, MWDOAS and MeFTIR measurements are generally not performed and because individual gas ratios are more uncertain than the average. Although not necessarily simultaneously measured, SOF and MeFTIR/MWDOAS measurements must represent the same source plume. Note also that gas ratios do not intrinsically depend on complete plume transects (like for direct flux methods) as long as the emission plume is well mixed at the sampling distance.

3.2.3 TRACER GAS FLUX MEASUREMENTS:

The third method to conduct flux measurements is by tracer correlations using only MeFTIR measurements or simultaneous MeFTIR and MWDOAS measurement and a known tracer gas release. These fluxes are given for each transect (*T*) by the following equation (Si-units in gray brackets):

$$Q_T^j[\mathrm{kg/s}] = Q^{tracer}[\mathrm{kg/s}]\,\frac{\int_P N_l^j[\mathrm{kg/m^3}]\,dl[\mathrm{m}]}{\int_P N_l^{tracer}[\mathrm{kg/m^3}]\,dl[\mathrm{m}]}$$

Where,

Q^{tracer} = the release mass flux of the tracer gas from bottle,
N_l^{tracer} = the number density concentrations of the tracer as measured by MeFTIR,
N_l^j = the number density concentrations of species *j* from MeFTIR or MWDOAS,

Note that tracer gas correlation fluxes do not intrinsically depend on complete plume transects (like for direct flux methods) as long as the emission plume and the tracer gas is well mixed at the sampling distance. Complete plume transects are, however, recommended since the tracer gas release point might not completely match at the sampling distance.

3.3 Uncertainties and Error Budget

A summary of the performance of the FluxSense measurements is presented in Table 4.

Table 4. Performance overview of FluxSense measurement methods.

Measurement Parameter	Analysis Method	Accuracy	Precision	Completeness*
SOF column concentrations alkanes, alkenes, NH_3	QESOF spectral retrieval	±10%	±5%	70-90%
SkyDOAS column concentrations NO_2, SO_2	DOAS spectral retrieval	±10%	±5%	70-90%
MeFTIR concentrations CH_4, VOC, NH_3, N_2O	QESOF spectral retrieval	±10%	±5%	95%
MWDOAS concentrations BTEX, Benzene	MWDOAS spectral retrieval	±10%	±5%	90%
Wind Speed (5 m)	R.M. Young Wind monitor	±0.3 m/s or 1%	±0.3 m/s	95%
Wind Direction (5 m)	R.M. Young Wind monitor	±5°	±3°	95%
Wind Speed (10 m)	Gill WindSonic	±2%	-	95%
Wind Direction (10 m)	Gill WindSonic	±3°	-	95%
LIDAR Wind Direction (50-1000m)	Leosphere Windcube 100S	-	-	>90% except in heavy fog
LIDAR Wind Speed (50-1000 m)	Leosphere Windcube 100S	±0.5 m/s	-	
GPS position	USB GPS receiver	±2m	±2m	100%
SOF mass flux Alkanes, alkenes, NH_3	SOF-Report flux calculations	±30%	±10%	80% (in suitable weather conditions)
MeFTIR+tracer mass flux Alkanes	SOF-Report MeFTIR+tracer flux calculations	±25%	±10%	95%
SkyDOAS mass flux NO_2, SO_2	SkyDOAS flux calculations	±30%	±10%	80% (in suitable weather conditions)

* For the optical measurements conducted in this project data completeness is difficult to estimate since the measurements are dependent on external parameters such as weather conditions.

Accuracy of measurement parameters is determined by comparing a measured value to a known standard, assessed in terms of % bias using the following equation:

$$\left[1 - \left(\frac{Measurement}{Standard}\right)\right] \times 100$$

Precision is a measure of the repeatability of the results. The precision for the SOF and mobile DOAS system is difficult to measure when inside the gas plumes. However, it is assumed that the precision of the instrument corresponds to the 1-sigma noise when measuring in clean air background. The precision of each instrument used in the project is listed in Table 4.

Data completeness is calculated on the basis of the number of valid samples collected out of the total possible number of measurements. Data completeness is calculated as follows:

$$\%\ Completeness = \left(\frac{Number\ of\ valid\ measurements}{Total\ possible\ measurements}\right) \times 100$$

3.4 Wind Measurements

The main source of wind information for this project was the FluxSense mobile 3-10 m wind mast equipped with a calibrated RM Young anemometer. The mast was, most of time, mounted on the bed of a pick-up truck and erected from 3 to 10 m depending on the studied object, see Figure 11. An open spot close to the source was chosen for the wind meter. For measurements with no relevant wind mast data available, wind data from an adjacent met station (SCAQMD, ASOS or internal Tesoro/Carson) was used, see Figure 10. For sea-based measurements, data from the AIRMAR sonic sensor, mounted on the top of the vessel (approximately 5 m above sea level), was used, see Figure 12.

Figure 10. SCAQMD and ASOS Met Stations in the Los Angeles basin. Map from Google Earth © 2016.

The largest source of error in SOF measurements of emission fluxes is typically the wind measurements. The flux is directly proportional to the wind speed (at average plume height) and to the cosine of the wind direction relative to the driving direction. The wind error is a combination of errors in the wind measurements themselves (see Table 4) and errors due to the assumption that the wind velocity measured in a particular way is representative of the average plume velocity. Note that MeFTIR+tracer flux calculations do not include any wind information (only indirectly dependence via wind turbulence mixing) and that the wind field uncertainty consequently can be ignored for these measurements.

Wind profile data, as supplied by a LIDAR, has the major advantage of allowing an average wind for an arbitrary height interval to be calculated. Given some approximate information about the mixing height of the plume, a suitable averaging interval can be chosen, and the LIDAR data can also be used to estimate the sensitivity of the wind error to the error in the mixing height. Hence, LIDAR data was main source of wind information for the refineries in Project-1 with extensive plumes, sampled several hundred meters downwind the facilities. For small sources in this project (Project-2) measured at a closer distance, the wind-LIDAR is typically not as suitable since its lowest sampling altitude of the LIDAR is 50 m.

Figure 11. FluxSense mobile wind mast mounted on the bed of pick-up truck. An RM Young anemometer is used throughout the project. The mast could be erected from 3 to 10 m.

First order estimates of the plume mixing height estimates can be retrieved by simultaneous concentration and column measurements with SOF and MeFTIR as described in Section 2.2. The method assumes homogeneous plume concentrations from ground level to the plume height and zero above, and results are used to indicate if the plume is close to ground or aloft where the wind speed changes less rapidly with height compared to close to ground. Results for some different small sources are found in Table 5. The results indicate a plume height of 13-150 m or 13-80 m if excluding the small refinery. This is considerably lower than for the large refineries in Project-1 which had an overall median plume height of around 400 m. Based on these plume height estimates, wind information from 10 m altitude has been used for all small sources (rather than using 50-400 m, as measured by the wind LIDAR).

The wind information from the car-based Airmar is not used for flux calculation since the wind field at street level can be quite disturbed and turbulent. This Airmar only acts as a real-time aid to keep track of the plume directions when making the gas emission measurements. The vessel-based Airmar (See Figure 12), on the other hand, is also used for flux calculations since the marine wind field is much less disturbed and the wind meter on the vessel is located immediately at the plume (land based met stations not applicable).

Figure 12. The research vessel for sea-based SOF measurements during the SCAQMD 2015 survey. The sonic wind sensor encircled in red at the top.

Table 5. Summary of plume height (median values) estimations from some typical small sources in the SCAQMD survey 2015 and used wind information. FS=FluxSense

Refinery	Number of Meas.	Median Plume Height [m]	Primary Wind	Secondary Wind
Refineries (Proj-1)	46	**413**	**LIDAR 0-400m**	**ASOS/SCAQMD/Tesoro**
Wells (Drilling Rigg)	2	13	**FS Wind Mast**	**ASOS/SCAQMD/Tesoro**
Wells (Derricks)	35	16	**FS Wind Mast**	**ASOS/SCAQMD/Tesoro**
Treatment Facility	16	37	**FS Wind Mast**	**ASOS/SCAQMD/Tesoro**
Small Refinery	15	152	**FS Wind Mast**	**ASOS/SCAQMD/Tesoro**
Tank Farm (large)	13	80	**FS Wind Mast**	**ASOS/SCAQMD/Tesoro**
Big Reservoir Tank	54	28	**FS Wind Mast**	**ASOS/SCAQMD/Tesoro**
Small Tank	27	43	**FS Wind Mast**	**ASOS/SCAQMD/Tesoro**
Offshore	-	-	**FS Airmar**	**-**

The FluxSense 10 m mobile wind mast was always the primary wind information for flux calculations in this survey. For cases where no relevant primary wind mast data was available, a secondary wind source was used, see Table 5. The secondary wind source was selected based on the proximity to the measured site and correlation.

In order to assess the sensitivity of the flux calculations to deviations from the assumed plume mixing height, wind LIDAR data (10 min average) from 50-100 m have been compared to the reference FluxSense 10 m wind mast during the calibration periods 2-6 October 2015 at site Tesoro Carson (see Figure 9). For this calibration period, the wind speed average at 50-100 m were systematically 20% higher than the 10 m mast data, see Figure 13, but the majority of data points are still within 30% of the wind mast. The wind direction is generally within 30°. The results from this calibration study gives an indication that the measured SOF fluxes for the largest of the small sources (large Tank Farms and Small Refineries) can be underestimated by a maximum of 20%, and presented fluxes are conservative.

For consistency no individual corrections for plume altitude are applied for the sources in this report because individual source plume height estimates are generally not available (lack of simultaneous SOF and MeFTIR data) and because conditions vary in space and time so that the calibration results from 2-6 October at Carson may not be representative for another particular site.

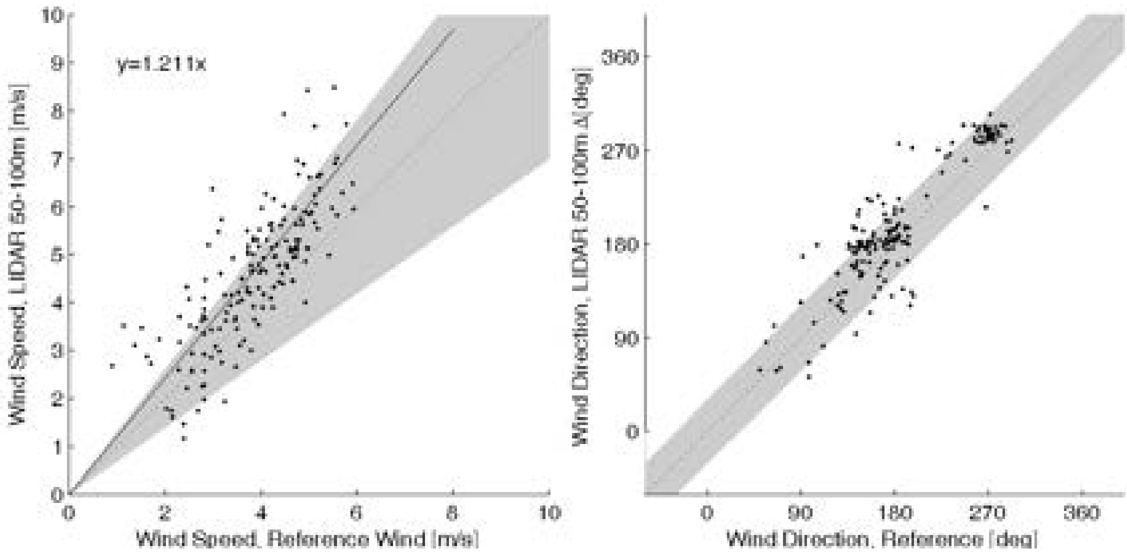

Figure 13. Wind LIDAR data (10 min average from 10AM to 5PM) for 50-100 m versus the reference FluxSense 10m wind mast during the calibration period 2-6 October 2015 at Tesoro Carson. The shaded areas indicate ±30% relative deviation from reference wind speed (left panel) and ±30° deviation from reference wind direction (right panel). Fitted least squares are shown as solid line.

An example of the evolution of the wind profile over the course of a day is shown in Figure 14. It shows a clear sign of the prevailing wind pattern throughout the study, with weak winds in the morning that increase in magnitude from approximately 10-12 AM and forward while also rotating clockwise. Since a wind speed of at least 1-2 m/s is typically needed in order to make accurate flux measurements, useful data could normally not be collected before 10 AM. As also seen in these examples, the wind is relatively homogenous within a layer up to 300-500 m, but at higher altitudes, the wind direction is often completely different indicating that this layer of homogenous wind is the convective boundary layer. The exact height of this layer varies throughout the day, and this explains why the wind is on average weaker and more variable in the uppermost levels of the 50-400 m height interval, as seen in Figure 14. The convective boundary layer simply does not always extend above this height level.

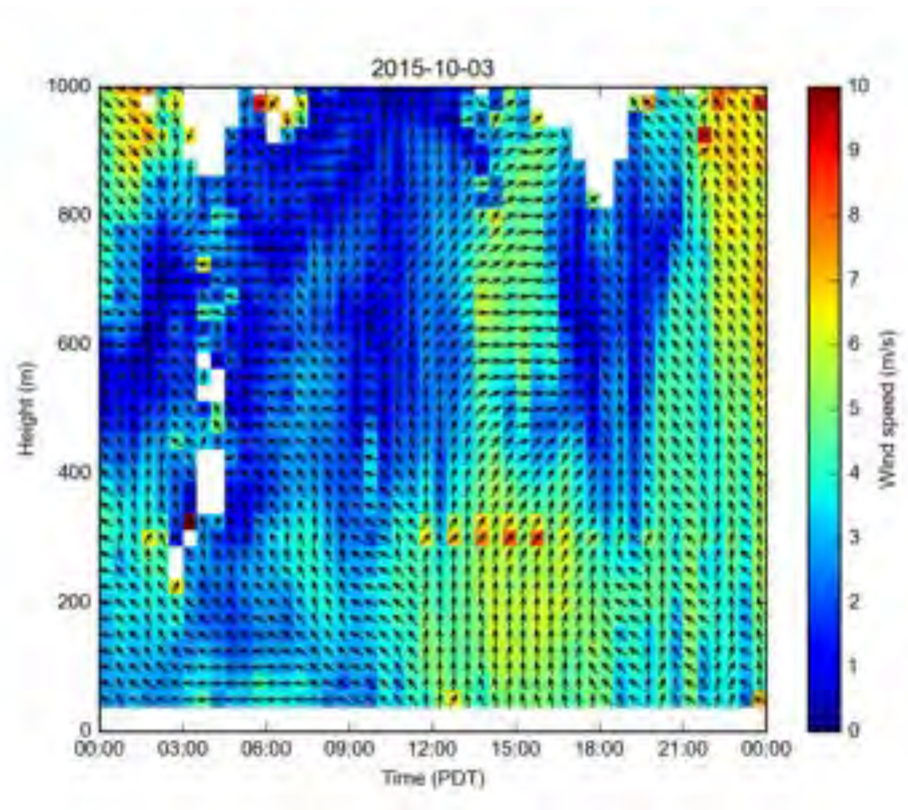

Figure 14. Wind LIDAR Raw data (30 min averages) from 50 to 1000 m at the L1 site in Carson measured on October 3, 2015. The color scale gives the magnitude of the wind speed and the black arrows show the wind direction (north up). The plot shows typical low wind speeds during night-time conditions and stable winds with little altitude variation (wind shear) from 50 to 400m in the period noon to sunset.

4 Results

In order to improve our understanding of emissions of VOC's, BTEX, NO2, and SO2 from a variety of stationary sources in the South Coast Air basin, emissions from 465 different units throughout the SCAB have been measured during this project. The studied sources have been categorized as following: *Oil & Gas Wells*, *Tank Farms*, *Terminals & Depots*, *Petroleum Treatment sites & Small Refineries*, *Gas Stations*, *Offshore Facilities & Activities* and *Other Sources*. Due to the large number of sources in the SCAB and the limited duration of the study, only a subset of sources has been sampled within each category, with differing statistical coverage between the source categories, see Table 6. For instance, 106 oil and gas wells have been measured, whereas there are over 5000 active wells in the SCAB [DOGGR 2016]. For VOC storage tanks in *Tank Farms*, *Terminals and Depots*, on the other hand, we estimate that nearly a half of such sources were included in this survey. This estimate is based on visual counting using Google Earth™. Note that any storage tanks in the other categories or in refinery tank parks (Project-1) are not counted here.

Table 6. Number of measured units in each category and total estimated number of units in the SCAB during the SCAQMD 2015 campaign- Project 2.

Source Category	Unit types	Number of Measured Units	Total Number of Units in the SCAB	Percent of Total Units Measured
1) *Oil & Gas Wells*	Derricks and Storage Tanks	106	5000†	2.1%
2) *Tank Farms, Terminals & Depots*	Tanks	328	750‡	44%
3) *Petroleum Treatment Sites & Small Refineries*	Entire site	9	15‡	60%
4) *Gas Stations*	Entire site	8	3140†	0.3%
5) *Offshore Facilities/Activities*	Entire site	7	20‡	35%
6) *Other Sources*	Entire site	7	unknown	unknown
7) *Uncategorized Area Source*	Various	1	unknown	unknown
Total number of units		**465**		

†Source: DOGGR 2016 database. ‡ Visual counting using Google Earth™.

Results for the different categories of stationary sources in the SCAQMD survey 2015 are presented in separate subsections below and summarized in Table 7. The geographical positions are given in Table 3 and marked as coloured areas and flags in Figure 9. The results in Table 7 are given as survey means per site and as total measured fluxes per category. The daily means and standard deviations are presented in the category subsections below. Average results per unit within each category are presented in Table 8.

Table 7. Average emissions from the sources in the SCAQMD-2015 Project-2 for each source category. N is a number of measurements.

Sources/Sites	*SOF or MeFTIR+tracer*	N	Alkane Flux [kg/h]	*MWDOAS* BTEX Flux [kg/h]	Benzene Flux [kg/h]	*MeFTIR* CH_4 Flux [kg/h]
Oil & Gas Wells (consisting of Derricks, Storage Tanks and Drilling Rigs)						
Wells_AtlanticAve_ESpringSt_SE	SOF	7	36	n.m.	n.m.	n.m.
Wells_WalnutAve_CrescentHeightsSt_NE*	SOF/M+T	31	21	n.m.	0.23	3.90
Wells_AtlanticAve_ESpringSt_SW	SOF	11	9.6	n.m.	n.m.	17
Wells_MarbellaAve_ESepulvedaBlvd_SSW	SOF	1	5.2	n.m.	n.m.	2
Wells_OrangeAve_E28thSt_NW	SOF	1	2.8	n.m.	n.m.	n.m.
Wells_RoseAve_CrestonAve_SW	SOF	39	7.8	0.18	0.07	15
Wells_TempleAve_E21stSt_SW	SOF	4	37	4.11	0.45	n.m.
Wells_ValenciaAve_ELambertRd_NW	SOF	1	1.6	n.m.	n.m.	n.m.
Wells_WalnutSt_W236thSt_SW	M+T	11	1.8	0.14	0.03	1.00
Wells_AtlanticAve_ESpringSt_NW	M+T	9	0.37	0.02	0.00	0.03
Wells_RoseAve_EWillowSt_S	M+T	3	0.05	0.01	0.00	0.06
Wells_GardenaAve_EBurnettSt_NW	M+T	4	2.3	n.m.	n.m.	0.51
Wells_NOrizaba_E20th_SE	M+T	7	0.17	n.m.	n.m.	0.07
Wells_PuertoNatalesDr_VinaDelMarAve_SE	M+T	11	1.4	0.10	0.01	0.82
Wells_RoseAve_CrestonAve_SW	M+T	4	3.4	0.08	0.03	1.80
Wells_JeffersonBlvd_BudlongAve_W	M+T	9	2.6	0.62	0.07	2.30
Wells_TonnerCanyonRd_W	M+T	21	5.5	n.m.	n.m.	n.m.
Total for "Wells" Category	**17**	**174**	**138**	**5.3**	**0.9**	**44**
Tank Farms, Terminals & Depots						
TankFarm_HarbourPlaza_SHarborScenicDr_SE	SOF	3	15	n.m.	n.m.	n.m.
TankFarm_PierASt_PierAPl_SW	SOF	5	13	n.m.	n.m.	n.m.
TankFarm_RedondoAve_EPacificCoastHwy_NE	SOF	1	7.1	0.59	0.07	6
TankFarm_SHenryFordAve_DockSt_NW	SOF	7	6.9	n.m.	n.m.	n.m.
TankFarm_SanClementeAve_SLaPalomaAve_W	SOF	7	39	n.m.	n.m.	n.m.
TankFarm_RedondoAve_EWillowSt_SW	SOF	3	24	n.m.	n.m.	n.m.
TankFarm_NParamountBlvd_ESouthSt_NW	SOF	9	43	6.71	0.65	n.m.
TankFarm_WEdisonWay_LuggerWay_SW	SOF	10	46	n.m.	n.m.	24
TankFarm_WarfSt_SeasideAve_SW	SOF	2	8.3	n.m.	n.m.	n.m.
TankFarm_FerrySt_PilchardSt_W	SOF	2	10	n.m.	n.m.	n.m.
TankFarm_OrangeAve_E25thSt_NE*	SOF/M+T	11	12	0.15	0.06	11
TankFarm_EdisonAve_PierBSt_SE	SOF	4	59	n.m.	n.m.	n.m.
TankFarm_JohnSGibsonBlvd_E	SOF	2	29	n.m.	n.m.	n.m.
Total for "Tank Farms, Terminals and Depots" Category	**13**	**66**	**314**	**7.4**	**0.8**	**41**
Petroleum Treatment Sites & Small Refineries						
TreatmentSite_WilmingtonAve_EDelAmoBlvd_SE	SOF	4	76	n.m.	n.m.	9
TreatmentSite_TempelAve_CombellackDr_SW	SOF	9	196	2.30	n.d.	37
TreatmentSite_StJamesPark_W23rdSt_SE	M+T	3	0.20	n.m.	n.m.	0.09
TreatmentSite_OrangeAve_ESpringSt_SE	SOF	24	170	3.50	0.81	125
TreatmentSite_LewisAve_EWillowSt_SE	SOF/M+T	13	14	1.29	0.34	13

TreatmentSite_GreenwichCir_RumsonSt_E	M+T	8	2	0.02	0.01	0.96
TreatmentSite_SMainSt_WSepulvedaBlvd_SSE	SOF	3	3.1	n.m.	n.m.	21
Refinery_LakewoodBlvd_SomersetBlvd_NW	SOF	7	24	2.84	0.34	n.m.
Refinery_ NParamountBlvd_EArtesiaBlvd_SW	SOF	5	16	1.81	0.23	n.m.
Total for "Petroleum Treatment Sites & Small Refineries" Category	**9**	**76**	**501**	**12**	**1.7**	**205**
Offshore Facilities & Activities						
OffShore_FuelIsland_Chaffet	SOF	2	12	n.m.	n.m.	n.m.
OffShore_FuelIsland_Freeman	SOF	2	8.2	n.m.	n.m.	n.m.
OffShore_FuelIsland_Grissom	SOF	1	3.98	n.m.	n.m.	n.m.
OffShore_FuelIsland_White	SOF	3	5.94	n.m.	n.m.	n.m.
OffShore_FuelBarges_PortLA	SOF	7	7.1	n.m.	n.m.	n.m.
OffShore_ShipVenting	SOF	2	27	n.m.	n.m.	n.m.
OffShore_ShipFueling	SOF	4	5.2	n.m.	n.m.	n.m.
Total for "Offshore Facilities & Activities" Category	**7**	**21**	**69**	n.m.	n.m.	n.m.
Gas Stations						
GasStation_CherryAve_EWillowSt_SE	M+T	13	2.24	0.51	0.06	0.48
GasStation_DowneyAve_RosecransAve_SE	M+T	15	0.57	0.10	0.01	0.47
GasStation_GoldenwestSt_YorktownAve_NE	M+T	7	1.71	0.62	0.07	0.50
GasStation_BeachBlvd_AdamsAve_NE	M+T	6	1.26	0.31	0.03	1.10
GasStation_CrenshawBlvd_SkyparkDr_NW	M+T	11	0.73	n.m.	n.m.	0.33
GasStation_CrenshawBlvd_WJeffersonBlvd_NW	M+T	8	2.58	0.68	0.07	0.35
GasStation_EOceanBlvd_ELivingstonDr_E	M+T	11	0.38	n.m.	n.m.	0.08
GasStation_WoodruffAve_HarveyWay_SE	M+T	5	0.45	0.10	0.01	0.03
Total for "Gas Stations" Category	**8**	**76**	**9.9**	**2.3**	**0.2**	**3.3**
Other Sources						
FuelSupply_SWesternAve_PalosVerdesDrN_SE	SOF	4	52	n.m.	n.m.	23
Seaside_45thSt_VistaDelMarBlvd	SOF	23	41	n.m.	n.m.	n.m
Airport_CherryAve_EWardlowRd_SE	SOF	3	60	25.9	n.d.	23
PowerPlant_TerminalIslandFwy_SeasideFwy_NW	SOF	1	30	n.m.	n.m.	n.m
OtherSite_AlamedaSt_PacificCoastHighwaySt_SO	SOF	2	74	n.m.	n.m.	5
Old_TankFarm_SignalSt_E22St_SE	SOF	5	29	n.m.	n.m.	n.m
Source_Valencie_Lambert_Brea_olinda	M+T	n.m.	n.m	n.m.	n.m.	12
Total for "Other Sources" Category	**7**	**38**	**286**	**26**	**n.m.**	**62**
Total Sum all Measured Sources	**61**	**451**	**1318**	*53†*	*3.7†*	*355†*
Uncategorized Area Source						
TankFarm&Refineries_Sepulveda_Alameda_SE	SOF	6	483	n.m.	n.m.	301

*Average of SOF and MeFTIR+tracer measurements (M+T). †Only sources where actual BTEX and CH_4 measurements were carried out are summed up here, leaving out any contributions from the ones not quantified. n.m. = not measured. n.d. = not detected (below detection limit).

Summing up emissions from all the 61 different measured sites/sources (including more than 450 units of wells, tanks etc.) and 451 SOF and MeFTIR+tracer transects resulted in a flux of 1318 kg/h of alkanes. Some of these sources (28) were also measured with MWDOAS and 35 with MeFTIR giving a sum of 53 kg/h of BTEX (3.7 kg/h of which were Benzene) and 355 kg/h of methane. Note that BTEX and methane measurements were not performed at all sites and, thus, these values are likely underestimated with respect to actual emissions from all sources. In addition, 483 kg/h of alkanes and 301 kg/h of methane were found from the uncategorized area source in Carson/Wilmington.

The category with largest measured emissions is *Petroleum Treatment Sites & Small Refineries* with 501 kg/h and followed by (in falling order) *Tank Farms, Tank Groups, Terminals & Depots* with 314 kg/h of alkanes; *Oil & Gas Wells* with 138 kg/h; *Offshore Facilities & Activities* with 69 kg/h; and *Gas Stations* with 9.9 kg/h. The order is similar when considering BTEX or Methane emissions, with the exception that these measurements were not performed for *Offshore Facilities & Activities* (the MWDOAS and MeFTIR instruments were not operated from the research vessel).

Average emissions of alkanes, BTEX and methane per unit source of each source category derived from this measurement campaign are presented in Table 8. Median BTEX and Methane fractions have been used to calculate emission fluxes but note that these measurements have not been performed for all sites (see Table 7). The average emissions from an *Oil & Gas Wells* unit (Storage Tank and/or Derrick) is 1.3 kg/h of alkanes, 0.1 kg/h of BTEX (of which 0.015 kg/h Benzene) and 0.3 kg/h of Methane. The emission for an average *Tank Farm* tank is 0.96 kg/h of alkanes and 0.08 kg BTEX (of which 0.01 kg/h Benzene).

Table 8. Average emission rates per unit in the different categories.

Source Category	**Unit Types**	**Number of Measured Units**	**Average Emissions per Unit**			
			Alkanes [kg/h]	**BTEX** [kg/h]†	**Benzene** [kg/h]†	**CH_4** [kg/h]†
Oil & Gas Wells	Derricks and Tanks	106	1.30	0.097	0.015	0.31
Tank Farms, Terminals & Depots	Tanks	328	0.96	0.079	0.0097	0.75
Petroleum Treatment Sites & Small Refineries	Entire Sites	9	55.7	3.23	0.77	27.4
Gas Stations	Entire Sites	8	1.24	0.31	0.033	0.31
Offshore Facilities/Activities	Entire Sites	7	9.79	n.m.	n.m.	n.m.
Other Sources	Entire Sites	7	40.9	n.m.	n.m.	15.5
Total Measured Units		**465**				

†Average emission fluxes of BTEX and CH_4 per unit are calculated by multiplying the average alkane flux per unit by the median BTEX or methane ratios within each category.

4.1 Oil & Gas Wells (Derricks, Tanks, Drilling Rigs)

Seventeen (17) different *Oil & Gas Wells* sites were observed during the survey, of which eight (8) with SOF and ten (10) with MeFTIR+tracer correlation (see cyan coloured flags and areas in Figure 9). Summing up all the measured sites gives 106 single units (Derricks and Storage tanks). The characteristics of the sites vary considerably as they contain different number of derricks, storage tanks and occasionally drilling rigs. Some sites comprise just a single derrick. The emissions varied considerably between sites (see Table 9 and Table 10), from a few grams per hour (RoseAve_EWillowSt_S) to over 60 kg/h of alkanes for individual transects (AtlanticAve_ESpringSt_SE). Higher emissions were observed during drilling events, and storage tanks at well sites were generally larger emitters than the derricks.

In total, based on 174 measurements, 138 kg/h of alkanes were detected from the observed Oil and Gas Wells sites. Examples of a typical SOF-transect and a MWDOAS/MeFTIR measurement are presented in Figure 16 and Figure 16, respectively. On average, 1.3 kg/h of alkanes per unit was measured; however the site-to-site variability was large, ranging from 0.05 kg/h/unit (Wells_RoseAve_EWillowSt_S) to 5.5 kg/h/unit (Wells_TonnerCanyonRd_W).

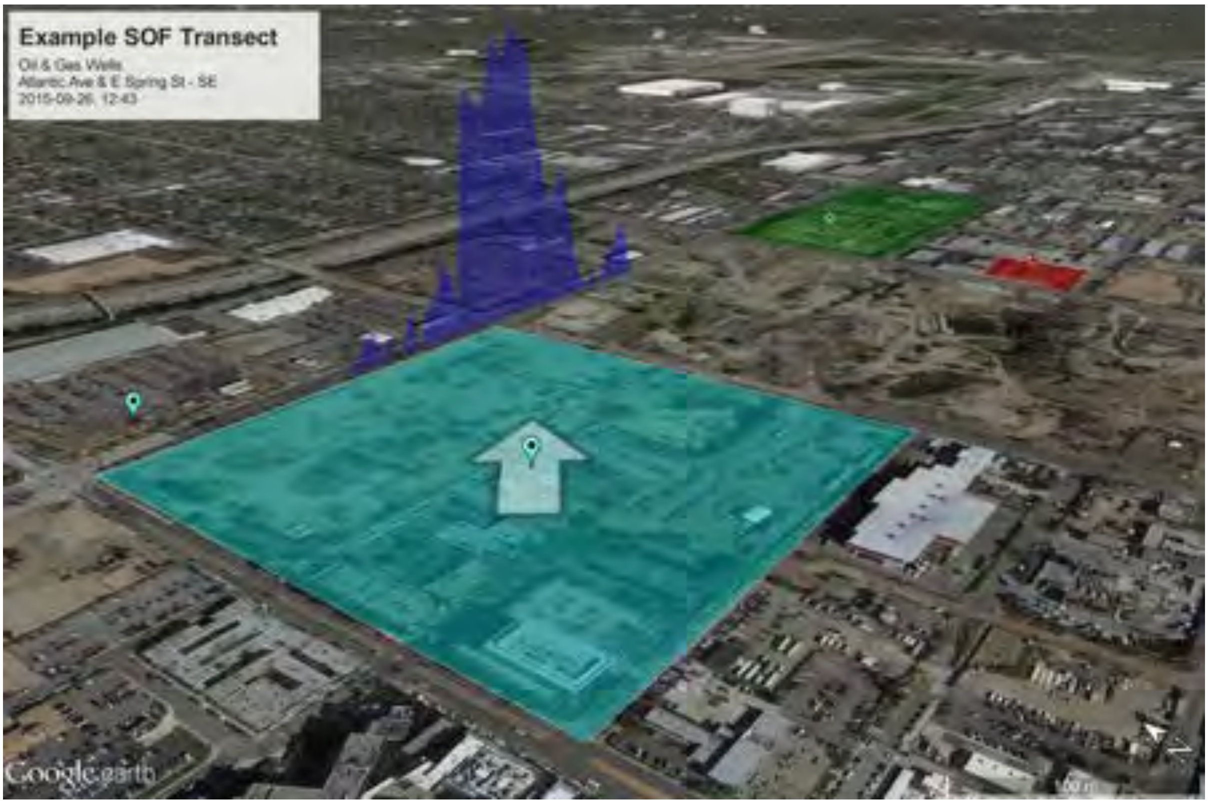

Figure 15. Example of a SOF measurement of Oil & Gas Wells at Atlantic Ave and E Spring St, Signal Hill, 26 October 2015, 12:43. Alkane column is shown as a blue curve with apparent height proportional to gas column (10 m equivalent to 1 mg/m^2, max 25 mg/m^2). Wind direction during the measurement is indicated by the white arrow, measured with the FluxSense 10m wind mast. Map from Google Earth™ 2016.

Table 9. Summary of alkane SOF measurements of *Oil and Gas Wells. N is equal to number of measurement transects.*

Source Oil & Gas Wells	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	Alkane Emission Mean±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
AtlanticAve_ESpringSt_SE	150926	124337 -124529	1	26	2.8	214
	151003	101714 -130549	4	45±21	3.1-4.8	150-174
	151008	160012 -160207	1	24	3.4	283
	151009	160735 -160917	1	20	4.7	301
WalnutAve_CrescentHeightsSt_NE	151003	121252 -121341	1	20	4.2	177
	151015†	131401 -152522	6	46±11	2.4-3.4	171-209
AtlanticAve_ESpringSt_SW	150926	123149 -135152	5	13±3.9	2.7-3.5	150-215
	151003	101813 -130418	5	6.8±4.9	2.8-4.1	152-187
	151008	154624 -154655	1	4.7	3.2	289
MarbellaAve_ESepulvedaBlvd_SS	151022	125709 -125840	1	5.2	2.4	170
OrangeAve_E28thSt_NW	151009	141949 -142038	1	2.8	2.9	281
RoseAve_CrestonAve_SW	151008	122003 -135335	39	7.8±3.5	1.4-2.9	135-198
TempleAve_E21stSt_SW	151003	92926 -93119	1	39	2.8	206
	151111	134427 -135027	3	36±40	1.9-2.4	284-329
ValenciaAve_ELambertRd_NW	151105	101647 -101725	1	1.6	1.8	120

† Ongoing drilling (see 4.1.1)

Table 10. Summary of alkane MeFTIR+tracer correlation measurements of *Oil and Gas Wells. N is equal to number of measurement transects*.

Source Oil & Gas Wells	Day [yymmd	Timespan [hhmmss-hhmmss]	N	Alkane Emission Mean±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
WalnutSt_W236thSt_SW	151025	124244 -133422	11	1.7±1.5	0.0-0.6	72-174
AtlanticAve_ESpringSt_NW	150926	141633 -143538	9	0.37±0.34	2.6-3.1	166-190
RoseAve_EWillowSt_S	151015	184252 -185050	3	0.05±0.05	0.5-1.1	291-326
GardenaAve_EBurnettSt_NW	151016	144950 -145639	4	2.2±2.5	2.2-2.7	263-305
WalnutAve_CrescentHeightsSt_NE	151016†	131452 -142845	18	12±10	0.5-4.0	45-327
	151022	205834 -212041	6	8.3±4.2	0.3-0.9	309-326
Jefferson_Budlong	151103	152830 -155933	9	2.6±2.2	0.0-4.0	1-353
PuertoNatalesDr_VinaDelMarAve_SE	151028	141643 -145659	11	1.4±1.3	1.1-1.6	172-227
RoseAve_CrestonAve_SW	151008	141416 -143119	4	3.4±2.2	0.8-1.9	173-227
TonnerCanyonRd_Brea*	150923	123131 -163259	21	5.5±2.2	1.7-3.9	172-257

† Ongoing drilling (see Section 4.1.1).
*Fracking event (see Section 4.1.2).

The fluxes of CH_4 and BTEX were measured either directly using MeFTIR+tracer correlation, or as an inferred flux based on the ratio of BTEX or CH_4 to alkanes. This ratio was then multiplied by the alkane flux measured from the same site using SOF. Both the CH_4 and the BTEX fluxes varied considerably between different well sites. Table 11 shows the fluxes for all measured single and groups of wells. The median fraction of CH_4 over alkanes including calculated fractions from the MeFTIR+tracegas measurements is 0.53. The median BTEX fraction for all 8 measured wells and well sites is 0.075 with variations from 0.02 to 0.27 as can be seen in Table 12. Also the internal BTEX composition showed large variations and was essentially all benzene during the drilling event described below. Examples of the measured BTEX and benzene plumes are presented in the chapter 4.9.

Table 11. Summary of MeFTIR CH_4 /Alkane mass ratio and CH_4 MeFTIR+tracer correlation measurements for *Oil and Gas Wells. N is equal to number of measurement transects*.

Source **Oil & Gas Wells**	**Day** [yymmdd	**Timespan** [hhmmss-hhmmss]	**N**	**CH_4/alkane mass ratio** [%]	**Tracer gas meas. CH_4 flux** [kg/h]
Wells_AtlanticAve_ESpringSt_SW	150926	134820 -135218	2	37	
	151003	110727 -110819	1	66	
Wells_MarbellaAve_ESepulvedaBlvd_SSW	151022	125833 -131933	2	43±7	
Wells_RoseAve_CrestonAve_SW	151003	122808 -122910	1	190	
Wells_WalnutSt_W236thSt_SW	151025	124244 -133422	11		1.0±0.7
Wells_AtlanticAve_ESpringSt_NW	150926	141633 -143538	9		0.03±0.02
Wells_RoseAve_EWillowSt_S	151015	184252 -185050	3		0.06±0.08
Wells_GardenaAve_EBurnettSt_NW	151016	144921 -145704	3		0.51±0.52
Wells_NOrizabz_E20th_SE	150922	191932 -203007	7		0.07±0.05
Wells_PuertoNatalesDr_VinaDelMarAve_S	151028	141643 -145659	11		0.82±0.61
Wells_RoseAve_CrestonAve_SW	151008	141416 -143119	4		1.8±1.5
Wells_JeffersonBlvd_BudlongAve_W	151103†	152830 -155933	8		2.3±0.9
Wells_WalnutAve_CresentHeightsSt_NE	151016†	131426 -142845	18		4.4±3.7
	151022	205834 -212041	6		3.4±1.4

† Ongoing drilling.

Table 12. Summary of MWDOAS/MeFTIR ratio measurements of *Oil and Gas Wells. N is equal to number of measurement transects*.

Source **Oil & Gas Wells**	**Day** [yymmdd]	**Timespan** [hhmmss-hhmmss]	**N**	**BTEX/alkane ratio** [%]	**Benzene/alkane ratio** [%]
WalnutSt_W236thSt_SW	151025	124255 -134024	11	7.9±4.2	1.6±1.2
AtlanticAve_ESpringSt_NW	150926	141644 -143433	9	5.3±4.7	1.1±1.7
RoseAve_EWillowSt_S	151015	184335 -185554	4	27.8±10.1	3.9±2.4
Jefferson_Budlong	151103	152322 -160146	7	23.6±18.0	2.7±2.0
PuertoNatalesDr_VinaDelMarAve_SE	151028	125945 -130432	2	7.1±9.1	0.67±1.11
RoseAve_CrestonAve_SW	151008	121740 -142323	15	2.3±0.7	0.88±0.23
WalnutAve_CrescentHeightsSt_NE	151015†	135132 -154623	8	2.7±0.5	2.7±0.3
	151016†	131314 -142834	10	3.1±3.3	1.2±0.2
TempleAve_E21stSt_SW	151003	93025 -93057	1	22.6	1.7
	151111	135238 -135303	2	5.5±3.1	0.98±0.73

† Ongoing drilling

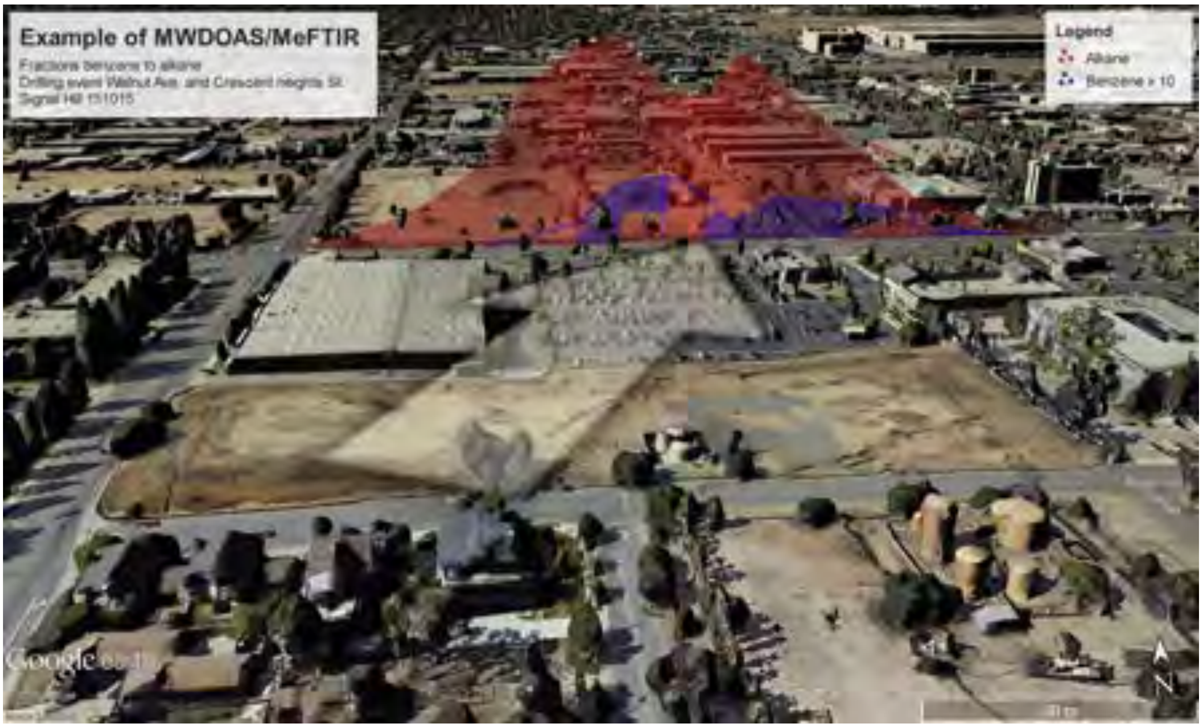

Figure 16. Example of a MWDOAS/MeFTIR measurement of Oil & Gas Wells at Walnut Ave. and Crescent Heights St., Signal Hill, 15 October 2015, 13:59. Alkane concentration is shown as a red curve and the BTEX (in this specific case the only present BTEX was benzene) is shown as a blue curve. The BTEX have been magnified x 10 for visibility. Wind direction during the measurement, indicated by the white arrow, was measured with the FluxSense 10m wind mast. Map from Google Earth™ 2016.

4.1.1 Drilling Event

Different stages of an oil well drilling event were captured during this measurement campaign. On the field bordered by Walnut Avenue, Crescent Heights St., the Ocean Crest Credit Union building and the Food 4 Less parking lot, a well drilling was observed on October 3, 15-16. The drilling rig was later replaced by a derrick which also was measured on October 22, 2015. The results from measurements conducted during drilling and oil pumping are presented in Table 13. The highest emissions (12 to 46 kg/h) was found during days of ongoing drilling and the lowest (8.3 kg/h) when the drilling rig had been replaced by a Derrick. The BTEX flux measured during drilling on October 15 and 16 consisted often almost entirely of benzene as can be seen in Figure 31. The BTEX to alkane fraction can be found in Table 12.

Table 13. Measured alkanes emissions of drilling event at well site WalnutAve_CrescentHeightSt_NE, Signal Hill. The drilling rig had been replaced by a Derrick for the last measurement day.

Source WalnutAve_CrescentHeightSt_NE	**Day** [yymmdd]	**Timespan** [hhmmss-hhmmss]	**N**	**Alkane Emission Mean±SD** [kg/h]	**Wind Speed Min-Max** [m/s]	**Wind Dir Min-Max** [deg]
Drilling rig (SOF)	151003	121252 -121341	1	20	4.2	177
Drilling rig (SOF)	151015	131401 -152522	6	46±11	2.4-3.4	171-209
Drilling rig (MeFTIR)	151016	131452 -142845	18	12±10	0.5-4.0	45-327
Derrick (MeFTIR)	151022	205834 -212041	6	8.3±4.2	0.3-0.9	309-326

4.1.2 Hydraulic Fracturing Event

A stimulation of an established well (API: 0405921759) by hydraulic fracturing (fracking) took place in the Tonner Road Canyon, Brea, on September 23, 2015. MeFTIR and MWDOAS measurements of both alkanes and BTEX using tracer gas were performed before, during and after the fracking event. Measurements started during the preparation phase at 13:30 and ended at 16:57. Emissions of alkanes of about 5.4 kg/h and a BTEX emission of ~0.23 kg/h was found throughout the entire measured period, with no significant difference in emissions detected before or after relative time of the fracking event. Details of the measurements are presented in Table 14.

Table 14. MeFTIR+tracer correlation measurements of fracking event at well site Tonner Canyon Rd, Brea (fracking commenced at 16:35).

Source TonnerCanyonRd	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	Alkane Emission Mean±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
Before 16:35	150923	123131 -163259	21	5.5±2.2	1.7-3.9	172-257
After 16:35	150923	163604 -165744	5	5.4±0.9	2.9-3.4	211-251

4.2 Tank Farms, Terminals & Depots

Fourteen (14) different *Tank Farms, Terminals & Depots* sites were observed during the survey, 13 of which with SOF and 1 with MeFTIR+tracer correlation (see yellow coloured flags and areas in Figure 9). The sizes of the sites vary considerably with different number of tanks and on-site activities. The alkane emissions also vary considerably between sites and from day to day (see in Table 15 and
Table 16) from 5 kg/h (FerrySt_PilchardSt_W) to 60 kg/h (EdisonAve_PierBSt_SE).

In total, alkane emissions of 314 kg/h were measured from the observed sites based on 66 measurements. Example of typical SOF-transects for different wind directions and measurement days for the same site is shown in Figure 17. On average 0.96 kg/h of alkanes per unit was measured, however, emissions varied from site to site, from 0.13 kg/h/unit (TankFarm_SHenry FordAve_DockSt_NW) to 4.63 kg/h/unit (TankFarm_WEdisonWay_LuggerWay_SW).

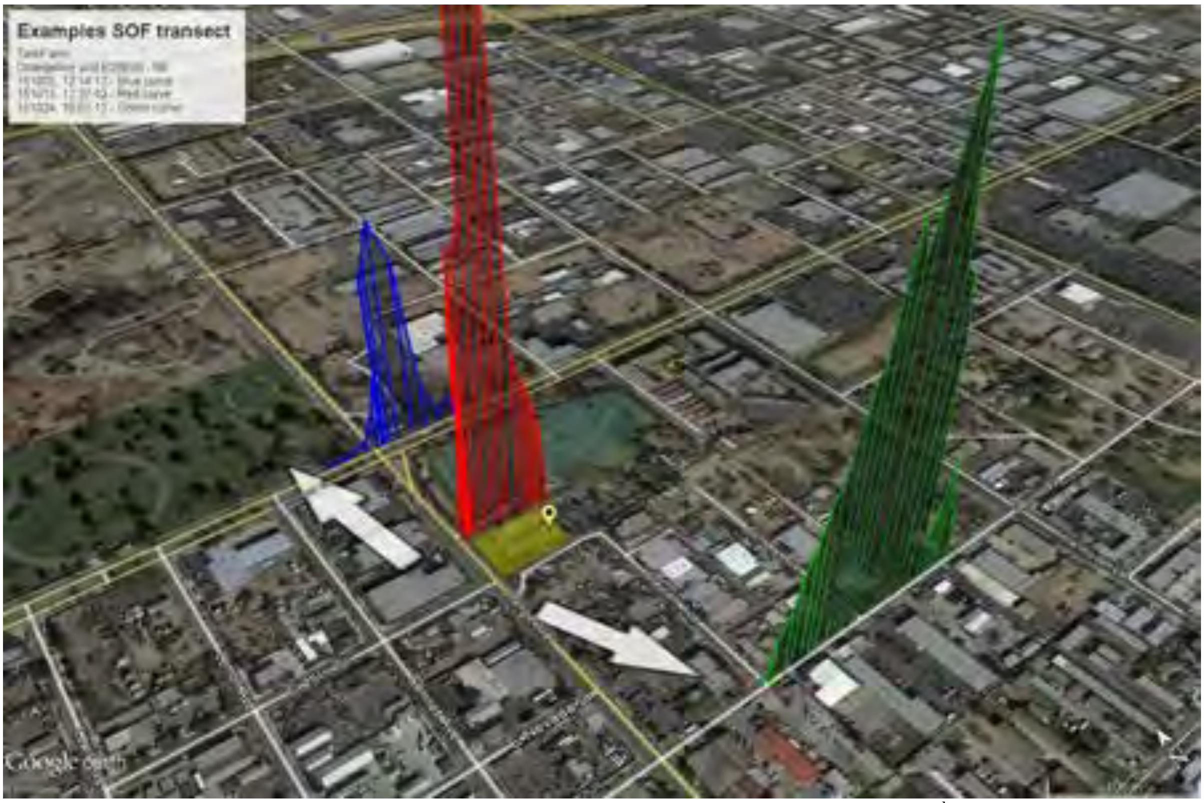

Figure 17. Example of a SOF measurement of a Tank Farm at Orange Ave and E 25th, Signal Hill. The figure shows measurements from the 3rd October 2015 12:14 (blue curve), 15th October 12:37 (red curve) and the 24th October 10:01. The apparent height of the curve is proportional to the measured alkane column (10 m equivalent to 1 mg/m^2). Both the red and blue measurement had similar wind direction. Map from Google Earth™ 2016.

Table 15. Summary of SOF measurements of *Tank Farms, Terminals & Depots.*

Source Tank Farms	**Day** [yymmdd]	**Timespan** [hhmmss-hhmmss]	**N**	**Alkane Emission Mean±SD** [kg/h]	**Wind Speed Min-Max** [m/s]	**Wind Dir Min-Max** [deg]
HarbourPlaza_SHarborScenicDr_SE	151015	151220 -154938	3	15±5.1	2.7-4.9	218-233
PierASt_PierAPl_SW	151020	145357 -152458	3	7.9±0.4	2.3-4.2	207-241
	151021	113343 -113757	1	3.6	3.1	167
	151026	160221 -160617	1	39.8	4.0	335
RedondoAve_EPacificCoastHwy_N	151003	113036 -113706	1	7.1	3.0	167
SHenryFordAve_DockSt_NW	150902	161552 -162626	3	6.1±2.2	2.3-2.7	208-231
	150906	173642 -174002	2	11±13	3.6-4.1	313-327
	151101	110538 -120024	2	4.4±3.2	3.3-4.0	186-202
SanClementeAve_SLaPalomaAve_	151020	152834 -161936	2	48±11	3.9-4.1	225-228
	151021	144744 -160709	4	36±19	2.8-4.4	177-212
	151026	133748 -134231	1	28.8	3.0	187
WEdisonWay_LuggerWay_SW	151101	114611 -114834	1	67	2.9	184
	151109	132035 -152947	9	44±18	3.3-6.2	249-316
WarfSt_SeasideAve_SW	151019	144434 -144856	1	7.9	4.0	184
	151021	112416 -113024	1	8.7	3.6	181
FerrySt_PilchardSt_W	151019	144928 -145331	1	15.6	3.3	175
	151021	121004 -121426	1	5.4	3.4	180
OrangeAve_E25thSt_NE	151003	121412 -121518	1	12.8	3.7	170
	151015	123742 -135034	4	13±8.5	2.1-4.7	161-221

	151024	100112 -105808	2	20±15	2.3-2.3	4-336
EdisonAve_PierBSt_SE	151101	115014 -142911	4	59.1±6.0	2.4-4.0	175-193
JohnSGibsonBlvd_E	151020	142902 -144147	2	29±2.8	3.5-4.6	225-242
NParamountBlvd_ESouthSt_NW	151023	111314 -142610	9	43±10	1.4-3.5	197-295

Table 16. Summary of MeFTIR+tracer measurements of Tank Farms.

Source **Tank Farms**	**Day** [yymmdd]	**Timespan** [hhmmss-hhmmss]	**N**	**Alkane Emission Mean±SD** [kg/h]	**Wind Speed Min-Max** [m/s]	**Wind Dir Min-Max** [deg]
OrangeAve_E25thSt_NE	151015	130611 -132744	4	9.5±3.9	2.8-4.0	168-195

CH_4 and BTEX was measured as inferred fluxes using the ratio to alkane measured with MeFTIR and MWDOAS. The results are shown in
Table 17 and Table 18, respectively. For all tank farms the CH_4 fraction was below 100%. Only one tank farm was measured with MWDOAS which showed a rather low fraction of 1.2% for BTEX.

Figure 18. Example of a MWDOAS/MeFTIR measurement of a Tank Farm along Paramount Ave, Paramount 23 October 2015, 12:17. Alkane concentration is shown as a red curve and the BTEX is shown as a blue curve. The BTEX have been magnified x 10 for visibility. Wind direction during the measurement, indicated by the white arrow, was measured with the FluxSense 10m wind mast. Map from Google Earth™ 2016.

Table 17. Summary of MeFTIR CH_4 /Alkane mass ratio and CH_4 MeFTIR+tracer of *Tank Farms, Terminals & Depots.*

Source **Tank Farms**	**Day** [yymmdd]	**Timespan** [hhmmss-hhmmss]	**N**	**CH_4/alkane mass ratio** [%]	**Tracer gas meas. flux** [kg/h]

RedondoAve_EPacificCoastHwy_NE	151003	113018 -113704	1	78
WEdisonWay_LuggerWay_SW	151104	165341 -165757	1	26
	151109	133858 -154923	9	55±20
OrangeAve_E25thSt_NE	151015	113616 -134815	10	92±49

Table 18. Summary of MWDOAS/MeFTIR mass ratio measurements of *Tank Farms, Terminals & Depots.*

Source Tank Farms	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	BTEX/alkane mass ratio [%]	Benzene/alkane mass ratio [%]
OrangeAve_E25thSt_NE	151015	133739 -134805	2	1.2±0.1	0.50±0.18

4.3 Petroleum Treatment Sites & Small Refineries

Nine (9) different *Petroleum Treatment Sites & Small Refineries* were observed during the survey, of which 7 with SOF and 3 with MeFTIR+tracer correlation (see green coloured flags and areas in Figure 9). A Petroleum Treatment site was typically identified as a site where product inflow from several wells is handled and also intermediately stored in storage tanks. Similarly to other sources, the size and emissions varied considerably between sites and from day to day (see

Table 19 and Table 20) from 0.2 (TreatmentSite_StJamesPark_W23rdSt_SE) kg/h to almost 200 kg/h (TreatmentSite_ TempelAve_CombellackDr_SW). In total, 501 kg/h of alkanes were detected from the observed sites, based on 76 measurements. An example of a typical SOF-transect of a small asphalt refinery is presented in Figure 19.

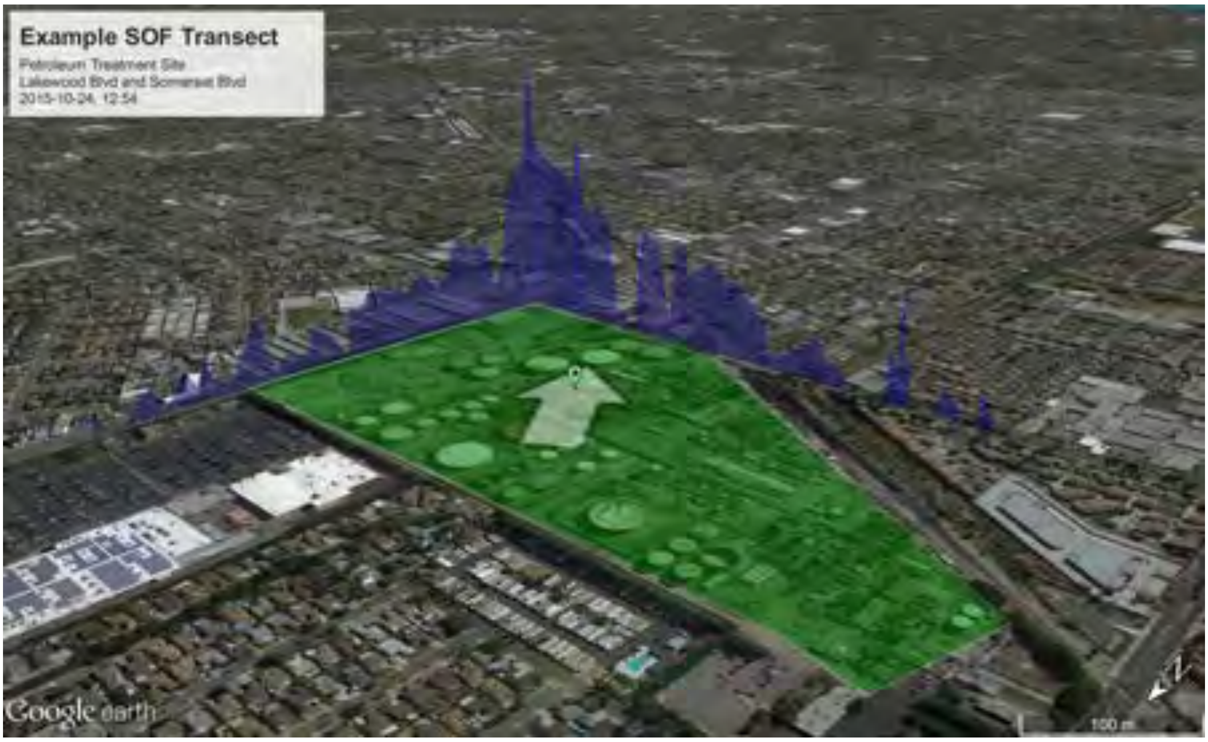

Figure 19. Example of a SOF measurement of an asphalt refinery at Lakewood Blvd and Somerset Blvd, Paramount, 24 October 2015, 12:54. Alkane column is shown as a blue curve with apparent height proportional to gas column (10 m equivalent to 1 mg/m^2, max 25 mg/m^2). Wind direction during the measurement is indicated by the white arrow, measured with the FluxSense 10m wind mast. Map from Google Earth™ 2016.

Table 19. Summary of SOF measurements of *Petroleum Treatment Sites & Small Refineries.*

Source Petroleum Treatment Sites and Small Refineries	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	Alkane Emission Mean±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
OrangeAve_ESpringSt_SE	150926	131449 -144834	2	361±2.2	3.4-3.6	163-179
	150927	103631 -103824	1	283	2.3	145
	151002	91454 -91542	1	288	2.5	98
	151003	101439 -132149	6	206±72	2.3-4.2	161-181
	151009	132355 -152637	12	124±48.0	2.3-4.7	272-315
	151024	110454 -111124	2	36±24	1.9-2.4	20-338
TempelAve_CombellackDr_SW	150926	151932 -152209	1	124	2.0	212
	151003	120954 -131802	8	205±97.5	3.2-4.3	172-185
LakewoodBlvd_SomersetBlvd_NW	151023	151816 -160054	3	20±7.2	3.0-3.2	254-268
	151024	125445 -142030	4	28±7.1	1.2-2.5	257-339
LewisAve_EWillowSt_SE	150926	132718 -132743	1	18	2.5	169
	151003	121516 -121542	1	16	4.1	173
	151015	132050 -152810	2	25±16	2.6-4.0	195-202
WilmingtonAve_EDelAmoBlvd_SE	151020	124818 -153308	3	77±17	1.9-5.8	140-255
	151030	125235 -125642	1	71	2.2	154
LakewoodBlvd_EArtesiaBlvd_SW	151023	120843 -141036	5	16±4.8	1.6-3.4	248-326
SMainSt_WSepulvedaBlvd_SSE	151022	132820 -134528	3	3.1±0.7	2.0-2.6	140-185

Table 20. Summary of alkane MeFTIR+tracer measurements of *Petroleum Treatment Sites & Small Refineries.*

Source Petroleum Treatment Sites	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	Alkane Emission Mean±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
StJamesPark_W23rdSt_SE	151019	165352 -170539	3	0.20±0.14	0.4-0.7	201-314
GreenwichCir_RumsonSt_E	151028	123336 -133531	8	2.0±1.2	0.3-2.4	159-219
LewisAve_EWillowSt_SE	151018	124654 -131121	9	5.9±3.1	1.8-2.6	155-221

CH_4 and BTEX fluxes were measured based on their ratio to alkanes. With the exception of a few outliers, the study median value for CH4/alkane ratio of 0.47 (see Table 21). For BTEX, small refinery sites had the highest BTEX/alkane ratio, which was approximately one order of magnitude higher than that at petroleum treatment sites (see Table 22). The site at LewisAve_EWillowSt_SE was the only exception, having BTEX/alkanes ratio similar to that of a small refinery.

Table 21. Summary of MeFTIR CH_4 /Alkane ratio and CH_4 MeFTIR+tracer measurements of *Petroleum Treatment Sites & Small Refineries.*

Source Petroleum Treatment Sites	Day [yymmd	Timespan [hhmmss-hhmmss]	N	CH_4/alkane ratio [%]	Tracer gas meas. flux [kg/h]
WilmingtonAve_EDelAmoBlvd_SE	151020	130139 -131317	2	7±4	
	151030	125139 -125707	1	21	
TempelAve_CombellackDr_SW	151003	95342 -123740	3	19±2	
StJamesPark_W23rdSt_SE	151019	165352 -170539	3		0.09±0.12

OrangeAve_ESpringSt_SE	150926	120808 -164604	8	38±17	
	150927	102925 -103148	1	43	
	151003	100000 -132148	7	180±120	
	151009	123830 -152632	1	46±14	
LewisAve_EWillowSt_SE	150926	132608 -132813	1	39	
	151015	124559 -153510	3	49±8	
	151018	121811 -133538	7	120±80	
GreenwichCir_RumsonSt_E	151028	123336 -133531	8		0.96±0.57
SMainSt_WSepulvedaBlvd_SSE	151022	130342 -134404	4	670±430	

Table 22. Summary of MWDOAS/MeFTIR ratio measurements of *Petroleum Treatment Sites & Small Refineries.*

Source **Petroleum Treatment Sites**	**Day** [yymmdd	**Timespan** [hhmmss-hhmmss]	**N**	**BTEX/alkane ratio** [%]	**Benzene/alkane ratio** [%]
OrangeAve_ESpringSt_SE	150926	120810 -124659	2	0.94±0.01	0.33±0.03
GreenwichCir_RumsonSt_E	151003	100106 -132105	8	2.7±1.4	0.41±0.15
	151009	132403 -155923	1	1.8±0.4	0.53±0.10
	151028	123752 -133517	3	1.2±0.4	0.53±0.08
LewisAve_EWillowSt_SE	151018	123520 -133244	1	9.5±3.8	2.5±1.5
TempelAve_CombellackDr_SW	151003	123409 -123627	2	1.2±1.1	0.41±0.26
LakewoodBlvd_SomersetBlvd_NW	151023	152547-155242	2	11.6±1.2	1.4±0.7
NParamntBlvd_EArtesiaBlvd_SW	151023	115136-142952	8	11.6±7.2	2.0±1.3

Figure 20. Example of a MWDOAS/MeFTIR measurement of a Treatment Facility at Spring St and Orange Ave, Signal Hill, 3 October 2015, 12:00. Alkane concentration is shown as a red curve and the BTEX is shown as a blue curve. The BTEX have been magnified x 10 for visibility. Wind direction during the measurement, indicated by the white arrow, was measured with the FluxSense 10m wind mast. Map from Google Earth™ 2016.

4.4 Offshore Facilities & Activities

Seven (7) different offshore sites and activities were observed during the survey with SOF (see blue coloured flags and areas in Figure 9). No MWDOAS or MeFTIR measurements were taken for the offshore sites since this instrumentation was operated in the mobile van and not mounted on the research vessel. The alkane emissions varied from 4 kg/h (Fuel Island Grissom) to 27 kg/h (Ship Venting), as seen in Table 23. In total, emissions of 69 kg/h of alkanes were measured from these sources based on 21 measurements. SOF-transects of three Fuel Islands on October 13, 2015 are shown in Figure 21.

Not all offshore emission source types were sampled during this campaign. For example, offshore sources not sampled within the scope of this work include offshore oil platforms located further off Long Beach, towards the Catalina Island. Large uncertainty also exists in a number of fuel barge operations, ship fuelling and venting activities. Therefore, there is a large uncertainty associated with scaling-up measured offshore emissions. A more viable approach would include more measurements to establish typical emission factors for these activities and then scale with data on number of operations within the port area, or handled product volumes where applicable.

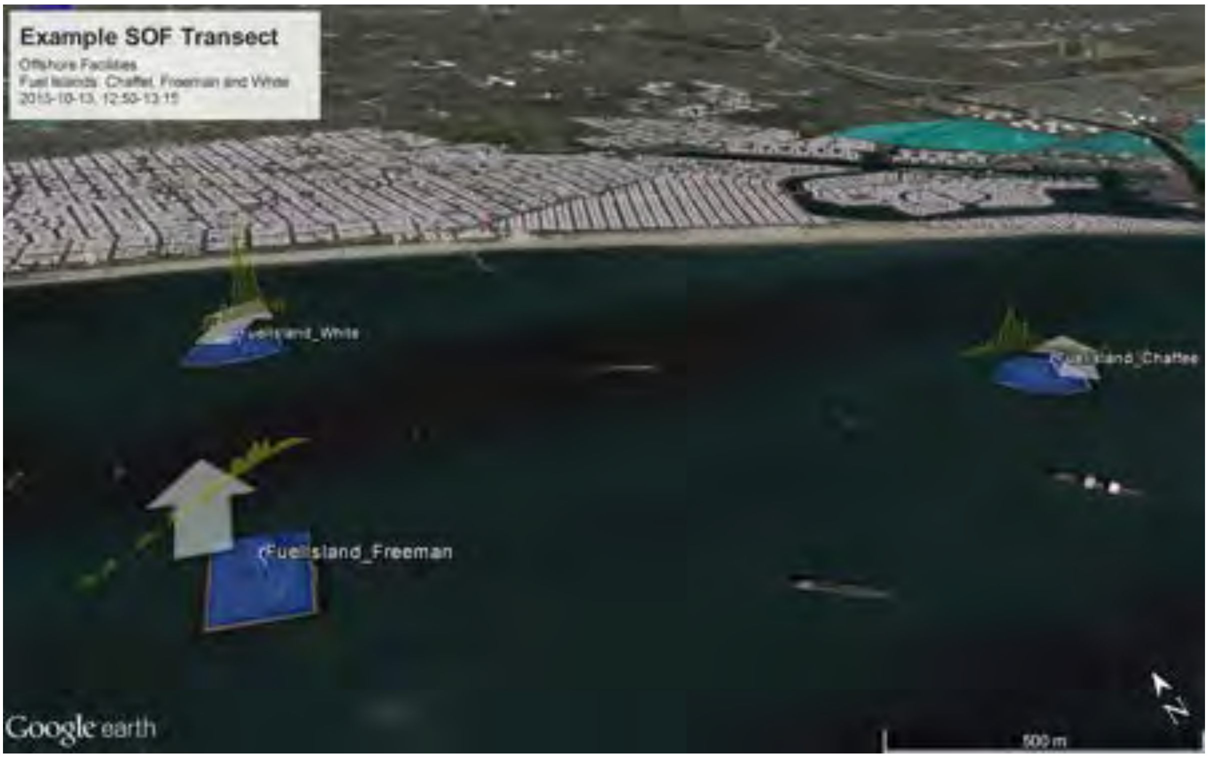

Figure 21. Example of SOF measurements of Fuel Islands outside Long Beach, 13 October 205, 12:50-13:15. Alkane column is shown as a yellow curve with apparent height proportional to gas column (10 m equivalent to 1 mg/m^2, max 35 mg/m^2). Wind direction during the measurement is indicated by the white arrow, measured with the FluxSense 10m wind mast. Map from Google Earth™ 2016.

Table 23. Summary of SOF measurements of *Offshore Facilities and Activities.*

Source Offshore	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	Alkane Emission Average±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
Fuel Island White	151013	131421 -132323	2	6.7±2.0	2.3-3.3	218-224
	151015	143335 -143511	1	4.5	4.0	232
Fuel Island Freeman	151013	125038 -125311	1	8.6	3.3	187
	151015	142832 -143049	1	7.9	5.4	232
Fuel Island Chaffee	151013	130322 -130526	1	6.9	1.7	221
	151015	141358 -141609	1	16	5.6	239
Fuel Island Grissom	151015	144825 -145121	1	4.0	3.4	222
Fuel Barges Port LA	151015	132908 -134256	2	8.1±6.7	4.5-6.6	204-244
	151026	122818 -161745	4	5.8±3.3	2.7-5.5	243-345
Ship Venting	151026	121948 -122550	2	27±1.2	5.7-6.3	213-229
Ship Fuelling	151026	131407 -161745	4	5.2±2.8	2.7-5.1	213-345

4.5 Gas Stations

Emissions from eight (8) different *Gas Stations* were measured during the survey with MeFTIR plus tracer (see pink coloured flags and areas in Figure 9). The number of fuel pumps and fuelling vehicles varied from site to site. The measured rates represent total emissions coming from gas station area, including fugitives from gasoline storage tanks, emissions during fuelling, and tail pipe emissions of vehicles driving to and from the station. In general emissions of alkanes were smaller compared to the other source categories and varied from 0.4 kg/h (GasStation_EOceanBlvd_ELivingstonDr_E) to 2.6 kg/h (GasStation_CrenshawBlvd_ WJeffersonBlvd_NW) (see Table 24). In total, 10 kg/h of alkanes were measured from the observed sites based on 76 measurements. An example of a typical MeFTIR-transect is given in Figure 22. The average tracer gas flow used was 3.7 kg/h but varied from site to site.

Figure 22. Example of a MeFTIR measurement of Gas station at Woodruff Ave and Harvey Way, Lakewood, 26 October 2015, 12:43. Alkane ground concentration is shown as a blue curve and tracer (N_2O) as a red with apparent height proportional to gas concentration. Wind direction during the measurement is indicated by the white arrow. Map from Google Earth™ 2016.

Table 24. Summary of alkane MeFTIR+tracer correlation measurements of *Gas Stations*.

Source Gas Stations	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	Alkane Emission Mean±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
BeachBlvd_AdamsAve_NE	151027	145236 -152049	6	1.3±1.8	1.0-1.7	225-249
CherryAve_EWillowSt_SE	151015	162256 -172752	13	2.2±2.2	2.0-4.0	45-304
CrenshawBlvd_SkyparkDr_NW	151029	174737 -184313	11	0.74±0.75	1.1-3.2	292-314
CrenshawBlvd_WJeffersonBlvd_N	151103	170227 -173202	8	2.6±1.1	4.0-4.0	230-230
DowneyAve_RosecransAve_SE	151023	174830 -184414	15	0.57±0.74	0.6-1.7	234-289
EOceanBlvd_ELivingstonDr_E	151101	170151 -180632	11	0.38±0.63	0.0-4.0	45-318
GoldenwestSt_YorktownAve_NE	151027	125724 -132405	7	1.7±1.3	0.2-0.6	255-346
WoodruffAve_HarveyWay_SE	151019	113047 -122626	5	0.44±0.28	1.6-2.3	197-208

BTEX flux was calculated from the measured BTEX/alkane ratio and can be found in Table 25. On average, BTEX to alkane mass fractions did not vary significantly from site to site and averaged at 26 % and 2.8 % for BTEX and benzene, respectively.

Table 25. Summary of MWDOAS/MeFTIR BTEX/alkane mass ratio measurements of *Gas Stations*.

Source Gas Stations	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	BTEX/alkane ratio [%]	Benzene/alkane ratio [%]
BeachBlvd_AdamsAve_NE	151027	151914 -153112	6	24.6±4.4	2.1±0.6
CherryAve_EWillowSt_SE	151015	162256 -172516	6	22.7±15.5	2.5±1.9
CrenshawBlvd_WJeffersonBlvd_N	151103	170237 -173303	7	26.5±12.0	2.9±2.1
GoldenwestSt_YorktownAve_NE	151027	125739 -134336	6	36.3±13.6	3.9±3.6
DowneyAve_RosecransAve_SE	151023	173531 -183136	6	18.1±9.6	1.9±0.6
WoodruffAve_HarveyWay_SE	151019	110801 -122601	19	22.4±16.8	2.7±2.9

4.6 Other Sources

Seven Other Sources were observed during the survey with SOF and MeFTIR (see white coloured flags and areas in Figure 9). Note that this category is a collection of remaining and unknown sources thus being very inhomogeneous with very different site characteristics.

The alkane emissions vary considerably between sites and from day to day as seen in

Table 26, from 14 kg/h (*Disused Tank Farm/Boat Loading*) to 80 kg/h (CherryAve_EWardlowRd_SE). On average, 286 kg/h were seen from all the observed sites based on 38 measurements. An example of a typical SOF-transect is seen in Figure 23.

Figure 23. Example of a SOF measurements of a VOC source west of Vista Del Mar Blvd in Long Beach, 11 September 2015, 11:05. Alkane column is shown as a blue curve with apparent height proportional to gas column (10 m equivalent to 1 mg/m^2, max 30 mg/m^2). Wind direction during the measurement is indicated by the white arrow, measured with the FluxSense 10m wind mast. Map from Google Earth™ 2016.

Table 26. Summary of alkane SOF-measurements of Other Sources.

Source Other Sources	Day [yymmdd	Timespan [hhmmss-hhmmss]	N	Alkane Emission Average±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
WesternAve_PalosVerdesDrN_SE *(Fuel Supply and Storage)*	150918	135615 -164251	4	52±15	3.5-5.6	301-324
45thSt_VistaDelMarBlv *(Power plant, Wells & Loading)*	150909	120758 -151047	5	31±9.0	5.3-5.9	256-274
	150911	110537 -114448	2	41±18	4.6-4.9	233-257
	150913	103832 -142124	5	50±38	3.8-7.1	237-261
	150914	124438 -124748	1	133	4.8	238
	150916	151907 -152320	1	26	5.4	262
	150920	112016 -134936	9	32±19	4.9-6.0	262-286
CherryAve_EWardlowRd_SE *(Airport Tanks and Facilities)*	150926	131039 -161635	2	80±37	3.6-3.7	201-314
	151111	123133 -123321	1	20	3.6	321
TerminalIslandFwy_SeasideFwy_N *(Power Plant)*	151101	115847 -115931	1	30	3.5	204
AlamedaSt_PacificCoastHwy St SE *(Car Scrap Yard & Painting?)*	150902	160210 -160237	1	51	4.2	289
	151110	143615 -143710	1	97	10.3	258
SignalSt_E22St_SE *(Disused Tank Farm/Boat Loading)*	151019	141833 -142541	1	37	5.9	175
	151020	135300 -170458	2	38±3.7	4.3-4.9	226-230
	151021	124345 -125423	1	14	3.5	183
	151026	130834 -131317	1	20	4.4	235

Table 27. Summary of MeFTIR CH_4 /Alkane ratio and CH_4 MeFTIR+tracer measurements of *Other Sources*.

Source **Other Sources**	**Day** [yymmdd]	**Timespan** [hhmmss-hhmmss]	**N**	**CH_4/alkane ratio** [%]
WesternAve_PalosVerdesDrN_SE	150918	144840 -145111	1	44
CherryAve_EWardlowRd_SE	150926	131056 -131203	1	38

Table 28. Summary of Summary of MWDOAS/MeFTIR ratio measurements of *Other Sources*.

Source **Petroleum Treatment Sites**	**Day** [yymmdd]	**Timespan** [hhmmss-hhmmss]	**N**	**BTEX/alkane ratio** [%]	**Benzene/alkane ratio** [%]
CherryAve_EWardlowRd_SE	150926	161604 -161625	1	43	3.4

4.7 Uncategorized Area Source

The Sepulveda_Alameda_SE source in Carson/Wilmington is large and diverse industrial area, including several different sites (tank farms, truck loading depots, refineries) which could not be separated using the fence-line measurements (at the prevailing wind direction). Hence, emissions from this area cannot be attributed to any of the categories in this study and is reported separately here. The average alkane emission of 483 kg/h, based on 6 measurements from 4 days (see Table 29), is however not insignificant in terms of the total SCAB emissions. The contribution from this area alone is around 4% of the total alkane emissions in the SCAB which is more than any other single large refinery of Project-1. The daily means varied from 268 kg/h on 29 August 2015 to more than two times that amount, 713 kg/h, on 3 September 2015. No valid BTEX measurements were done on this area source during the survey but a couple of methane measurements indicated a high methane to alkane ratio of 63% (see Table 30).

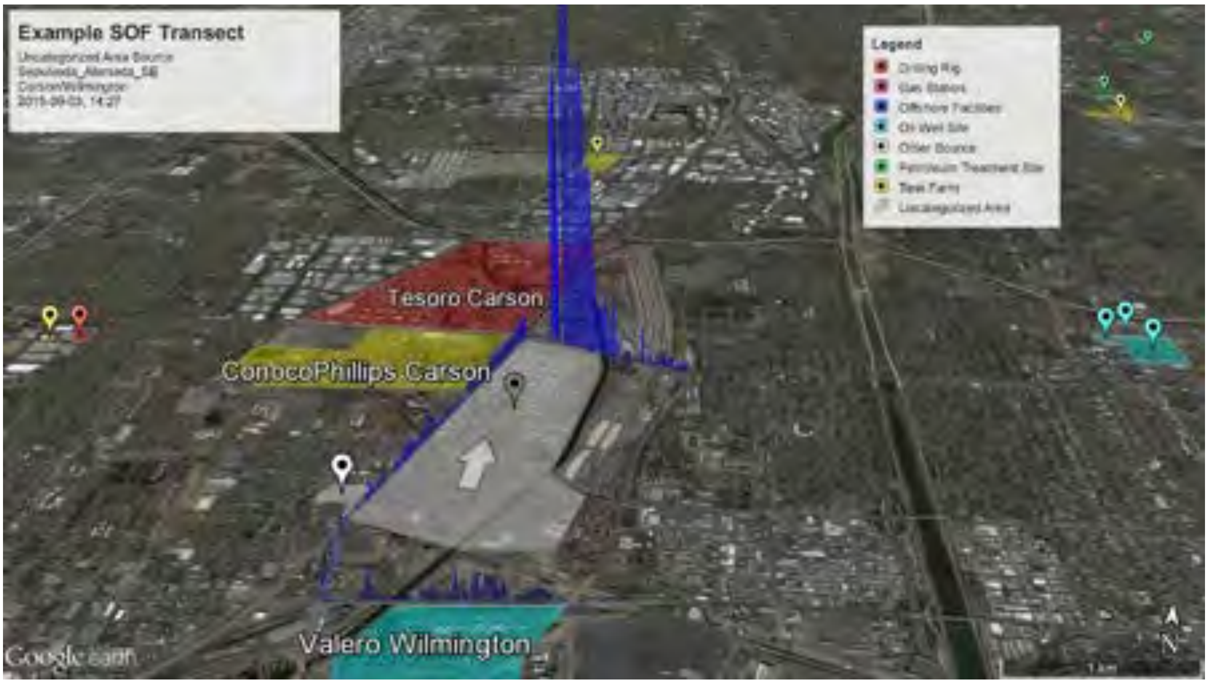

Figure 24. Example of a SOF measurement transect of the *Uncategorized Area Source* (gray shaded area) in Long Beach, 3 September 2015, 14:30. Also noted are large Refineries from Project-1 (names) and other surrounding sources from Project-2. Alkane column is shown as a blue curve with apparent height proportional to gas column (10 m equivalent to 1 mg/m^2, max 400 mg/m^2). This particular transect gave 750 kg/h. Wind direction during the measurement is indicated by the white arrow. Map from Google Earth™ 2016.

An example of a measurement transect during southern winds is found in Figure 23. Strong columns were found on the downwind (northern) side and only weak columns on the upwind (southern) side. Note the size of the area and the proximity to other large sources in all directions except on the east side. Measurements during easterly winds would be useful for separating the different sites within the area but were not conducted during the study since this wind direction is rare.

Table 29. Summary of alkane SOF-measurements of *an Uncategorized Area Source* in Carson/Wilmington.

Source Uncategorized Area Source	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	Alkane Emission Average±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
Sepulveda_Alameda_SE *Tank farm, Terminal & Refineries*	150903	142758 -144507	2	713±55	3.5-3.9	156-182
	150904	132219 -133100	1	327	5.0	179
	151003	140703 -143238	2	438±177	5.4-5.4	159-181
	150829	141048 -141744	1	268	3.2	184

Table 30. Summary of MeFTIR CH_4 /Alkane mass ratio of an *Uncategorized Area Source* in Carson/Wilmington.

Source Uncategorized Area Source	Day [yymmdd]	Timespan [hhmmss-hhmmss]	N	CH_4/alkane ratio [%]
Sepulveda_Alameda_SE	151018	145455 -150436	2	63

4.8 Cattle Farms

NH_3 emissions from *Cattle Farms* in Chino were measured on October 17, 2015 by high resolution (0.5 cm^{-1}) SOF measurements. Total NH_3 emission form the area outlined by the orange rectangle in Figure 25 was 245 kg/h based on three large box measurements (area 4 by 5 km; see Table 31). We estimated 17 cattle farms located within the orange box.

Table 31. Summary of SOF ammonia (NH_3) measurements at *Cattle Farms* in Chino.

Day [yymmdd]	Timespan [hhmmss-hhmmss]	No. of Transects	Ammonia Emission Average±SD [kg/h]	Wind Speed Min-Max [m/s]	Wind Dir Min-Max [deg]
151017	133330 -160319	3	245±19.5	3.8-4.4	234-244

Characterization of the mass concentration ratio of methane to ammonia was performed using MeFTIR in five plume integrations between 14:15-17:44 on October 17, 2015. The plumes of methane and ammonia were co-located, and the integrated cross plume mass ratio of methane to ammonia was on average 2.2±0.3 (± 1 SD), see Table 32. The ammonia flux average of 245±20 kg/h from SOF measurements and the methane to ammonia plume mass ratio of 2.2±0.3 from the MeFTIR measurements infers a methane emission from the sampled area of 540 kg/h.

Table 32. Integrated plume mass ratio of methane to ammonia measured with MeFTIR at *Cattle Farms* in Chino.

Day [yymmdd]	Timespan [hhmmss-hhmmss]	No. of Transects	Methane to ammonia mass ratio Average±SD [%]
151017	141506 -174433	5	220±30

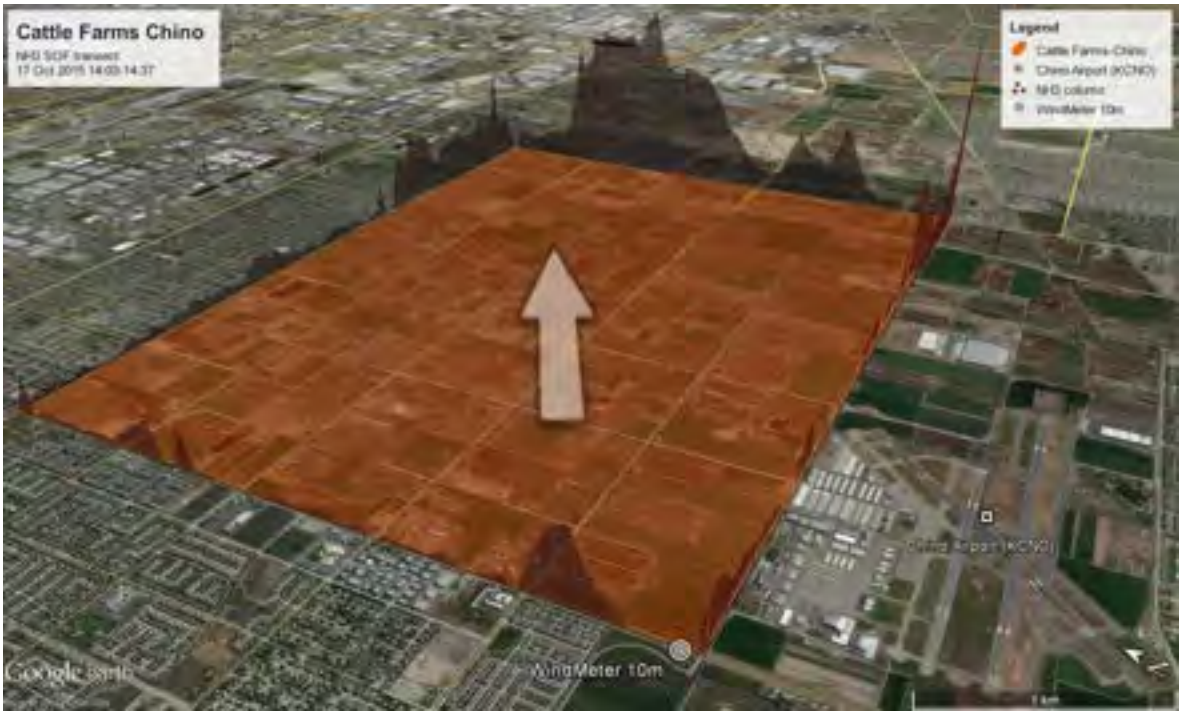

Figure 25. Example of a SOF 'box' measurement of cattle farms in Chino (orange area) refinery 17 October 2015, 14:03-14:37. NH_3 column is shown as a brown curve with apparent height proportional to gas column (100 m equivalent to 1 mg/m^2, max 22 mg/m^2). Wind direction during the measurement is indicated by the white arrow, measured with the FluxSense 10m wind mast (white circle in the map). Map from Google Earth™ 2016.

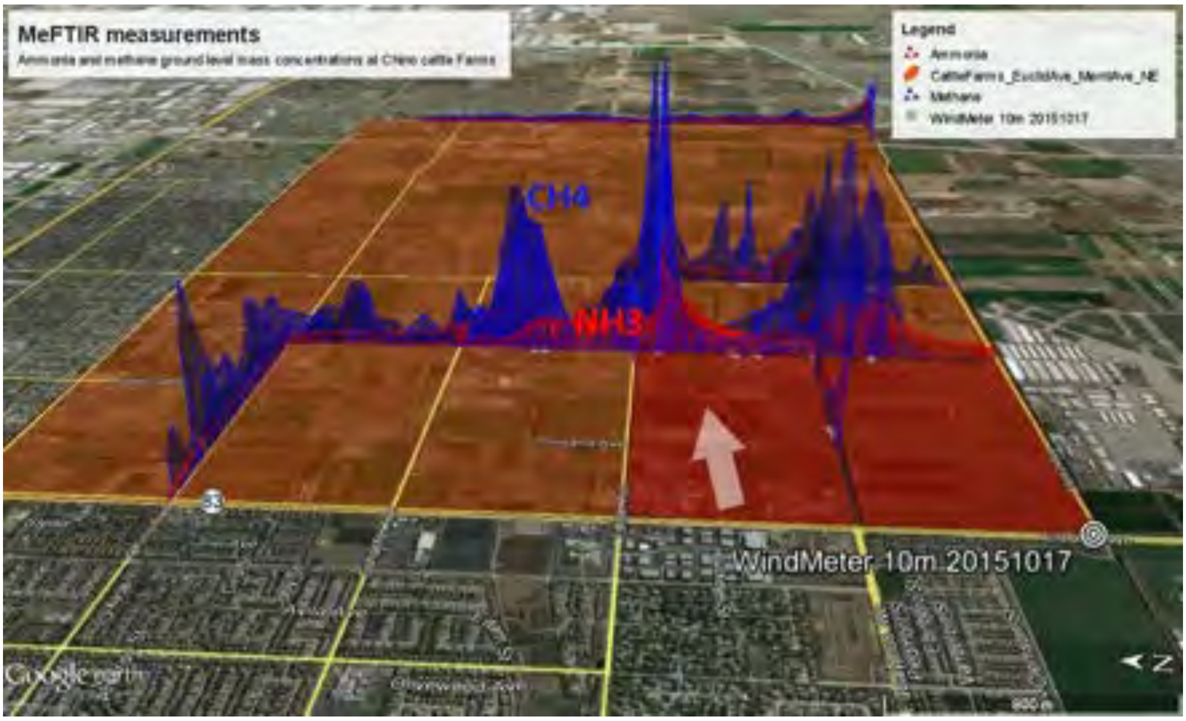

Figure 26. Methane and ammonia ground level concentration measurements with MeFTIR at cattle farms in Chino on October 17. NH_3 concentration is shown as a red curve with apparent height proportional to gas concentration (max 274 μg/m^3). Methane is shown as a blue curve (max 1300 μg/m^3). Wind direction during the measurement is indicated by the white arrow, measured with the FluxSense 10m wind mast (white circle in the map). Map from Google Earth™ 2016.

4.9 Real-time concentration mapping of BTEX and benzene

In addition to locating and quantifying sources of alkanes, BTEX and methane emissions within this project, ground-level concentration mapping of these species were also conducted using MeFTIR and MWDOAS. In some instances, elevated levels of benzene (above 1 ppb over the background) were detected while driving around the known emission source, and the plume was mapped by driving away form that source. Further source identification was performed by detecting a pollution plume(s) and triangulating from the plumes back to the source using the wind direction. Therefore, these mobile surveys can also be used as a tool to assess actual HAP exposure levels in residential areas and sensitive receptors located near the sources. Real-time mobile concentration measurements of BTEX, alkanes and methane, combined with the corresponding SOF alkane flux measurements, were also used to calculate BTEX and methane fluxes.

Figures 27 through 35 show examples of concentration mapping conducted during the project, these examples represent typical sources observed during the study. The total BTEX is shown as a solid black line and the benzene only is shown as a solid blue line; concentrations are presented in [µg/m^3].

On October 25, 2015, FluxSense mobile laboratory measured emissions from an oil well site containing derricks and storage tanks located in a residential area near Sur La Brea Park in Torrance. During this survey, BTEX levels of up to 140 µg/m^3 were measured, 45 µg/m^3 (or 14.1 ppb) of which were benzene (see Figure 27).

Figure 27. Emission from derricks with associated tanks (main source) at Sur La Brea Park, denoted "Wells_WalnutSt_W236thSt_SW" in the result section, on October 25, 1:35 -1:41 pm. BTEX levels up to 140 µg/m^3 was observed on the nearby street, of which 45 µg/m^3 was benzene. Wind speeds were low at the time, about 1-2 m/s. Each measured spectrum is represented with a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by distance driven through the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing.

After MWDOAS detected the BTEX plume, an infrared gas camera (FLIR, kindly supported by SCAQMD Long Beach office) was used to visualize the observed emissions, see Figure 28, showing several gas leaks on a couple of tank roofs and pipes.

Figure 28. After MWDOAS detected the BTEX plume at the site by Sur La Brea Park (Figure 27), an infrared gas camera (FLIR) was used to visualize the observed emissions. To the left is a photo of the site, with the gas camera in the foreground. To the right a snapshot from the infrared camera is shown, with emerging gas enhanced by a yellow line here. VOC was being emitted from many leaks on the tank roof and pipes, and the gas is seen as black or white against the grey background.

Figure 29 shows a measurement along E Burnett Street in Signal Hill in the afternoon of October 8, 2015. During this survey, we measured BTEX levels up to 220 µg/m^3, of which 40 µg/m^3 (12.5 ppb) were benzene.

Figure 29. Emission from several wells and tanks measured along E Burnett street in Signal Hill on October 8, 1:58-2:08 pm. Each measured spectrum is represented with a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by distance driven through the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing.

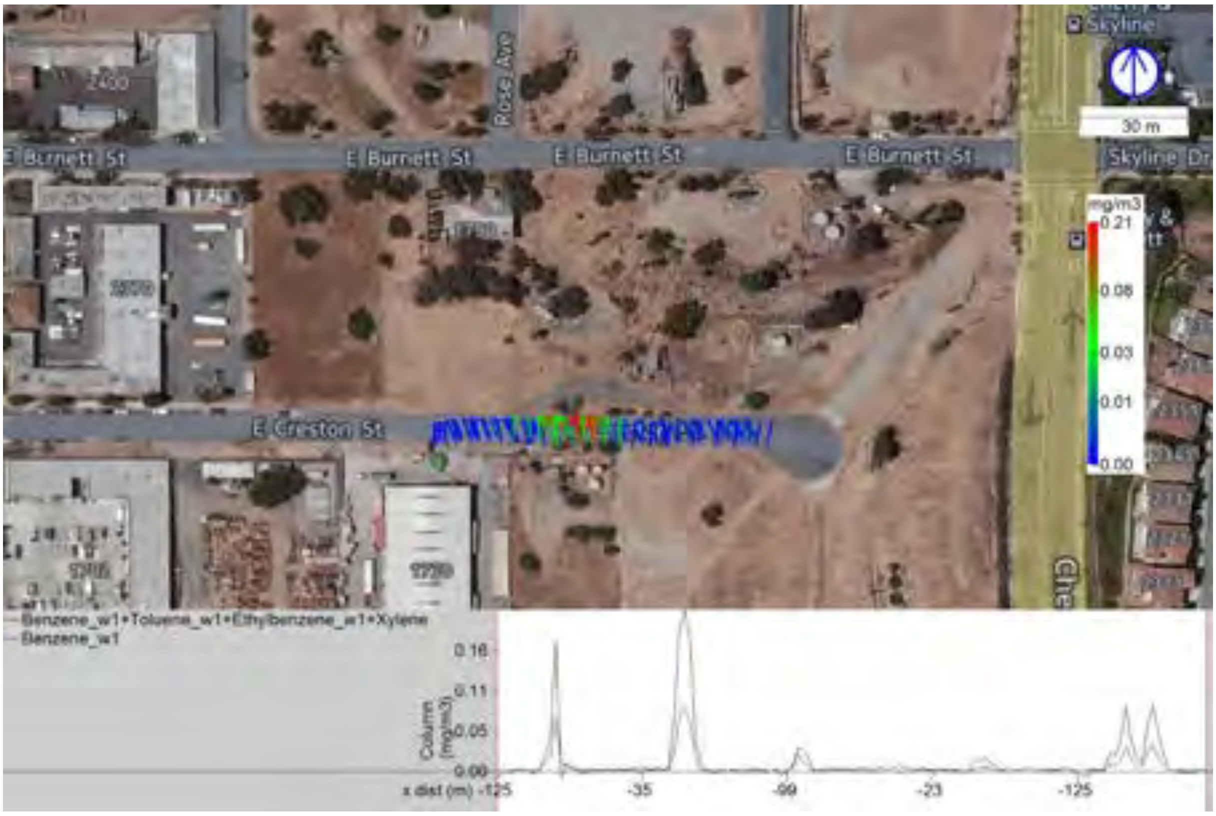

Figure 30. Emission from the well and tanks denoted "Wells_RoseAve_CrestonAve_SW" in the result section, on October 8, 12:31-12:39 am. Each measured spectrum is represented with a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by distance driven through the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing.

Figure 30 shows a measurement in the same area and same day (October8, 2015 at 12:35 pm), performed in closer proximity to the suspected source on E Creston St, verifying that it was the dominating source of the observed elevated BTEX concentrations. BTEX levels up to 210 µg/m^3, of which benzene was 83 µg/m^3 (26 ppb), were measured on the street near the source. Winds were blowing from the south at about 2 m/s. Further investigation with a FLIR camera identified a vent of one of the tanks as the main source of emissions.

On October 15 and 16, 2015 flux measurements and BTEX concentration mapping was done at a well site near E 25th Street (also referred to as Crescent Heights Street, see Table 13) in Signal Hill, see Figure 31. During this time period, a drilling rig was active at the site, and increased alkane emissions were observed on 15 October compared to earlier measurements on 3 October when no drilling occurred, see Table 9 and Table 10. High benzene concentrations of up to 180 µg/m^3 (56.4 ppb) were detected in the neighbourhood (see Figure 31) during 15 and 16 October.

Figure 31. Emission from the drilling site at Walnut Avenue and Crescent Heights on October 16, 12:35-12:41 am. Both on October 15 and 16 high levels of benzene was measured downwind this site. This measurement showed BTEX levels up to 210 µg/m^3, of which benzene 180 µg/m^3. Wind speed was about 1-1.5 m/s, coming from WSW. Enclosed is a photo of the drilling rig, with the rig position indicated by the orange arrow, and with the FluxSense mobile lab in the foreground. Each measured spectrum is represented with a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by distance driven through the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing.

SOF emission flux measurements as well as BTEX mapping with MWDOAS were carried out on multiple days (see

Table 19), from a petroleum treatment/separation site near the intersection of Orange Ave and E Spring St, in Signal Hill. Figure 32 shows a plume transect on October 3, 2015 at 10:10 AM, depicting BTEX levels of up to 230 µg/m^3 on E Spring St, of which benzene was 27 µg/m^3 (8.5 ppb). The wind was blowing from south at 3.5 m/s. By means of a FLIR gas imaging camera, the roof of the largest tank on the site (furthest south) was identified as the main emission point.

Figure 33 shows an extended plume transect at a well field and petroleum treatment site located in a residential area in Yorba Linda, near Buena Vista Ave and Greenwich Circle. The measurements were conducted in close proximity to the site as well as while following the plume further away to a distance of 200 m. BTEX levels of up to 110 µg/m^3 were measured near the site and of up to 21 µg/m^3 at 200 m distance. Corresponding benzene levels were 46 and 3 µg/m^3 (14. 1 and 1 ppb), respectively. By use of a FLIR camera, a leaky tank roof on the site was identified as the main emission source. The wind speed was about 2 m/s from SSW.

A small tank farm near Orange Ave and E 25 Street in Signal Hill, was measured on October 15, 2015 at 1:45 PM, see Figure 34. A plume of up to 60 µg/m^3 BTEX, of which 35 µg/m^3 (11 ppb) benzene was observed from the site. Similarly to the other sites, a tank roof vent was identified as a main source of emissions. The wind speed at this occasion was 5 m/s.

Figure 35 shows a measurement at a gas station located at the intersection of Cherry Ave and Willow St, Signal Hill conducted on October 3, 2015. Concentrations of up to 26 µg/m^3 BTEX were measured, 4 µg/m^3 of which was benzene, at 160 m distance from the source and a wind speed of 2.5 m/s.

Figure 32. Emission on October 3, 10:10-10:12, from the treatment site denoted "TreatmentSite_OrangeAve_ESpringSt_SE" in the result section. Each measured spectrum is represented with a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by distance driven through the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing. The wind was blowing from south at 3.5 m/s.

Figure 33. Emission on October 28, 1:23-1:28 pm, from the treatment site denoted “TreatmentSite_GreenwichCir_ RumsonSt_E” in the result section. Each measured spectrum is represented with a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by distance driven through the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing. The wind speed was about 2 m/s from SSW.

Figure 34. Emission on October 15, 1:46-1:48 pm, from the tank farm denoted “TankFarm_OrangeAve_E25thSt _NE” in the result section. Each measured spectrum is a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by distance driven through the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing. Wind speed was about 5 m/s, coming from SSW.

Figure 35. Emission on Oct 15, 5:02-5:04 pm, from the gas station at Cherry Ave. and E Willow St. in Signal Hill. Each measured spectrum is represented with a point, with color and size indicating the evaluated integrated vertical BTEX column according to the logarithmic color bar. The BTEX (black) and benzene (blue) column by time standing still in the plume is also shown in the lower part of the figure. A line from each point indicates the direction from which the wind is blowing. Wind speed was about 2.5 m/s, coming from W, and the distance from sample position to the source was 160 m.

5 Discussion and Conclusions

Emission measurements of Alkanes, Methane and BTEX in the South Coast Air Basin (SCAB) have been carried out by FluxSense Inc. using several optical remote sensing techniques during a 2-month campaign from September through November, 2015. This report covers Project 2, which focused on small stationary sources of VOCs, in which emissions from 61 sites and six different categories were quantified. Concentration mapping of areas surrounding those sources was also conducted. VOC emissions from an uncategorized area source in Carson/Wilmington, which included multiple unidentified sources, were measured but reported separately due to unfavorable meteorological conditions and lack of accessible roads. A brief study of ammonia and methane emissions from cattle farms in Chino was also conducted.

During Project 2, 451 flux measurement transects and 303 gas mass ratio measurements were performed. The number of measurements for each site varied from a single measurement to more than 30. The final data for each source is presented as daily mean as well as survey mean. When more than one measurement was conducted, the standard deviation is also reported. The reported values are only representative of the time period covered by this study, and the measurement uncertainty depends on the number of samples collected. Single emission values should be considered as snap-shots. Note also that flux measurements of BTEX and methane derived from MWDOAS and MeFTIR measurements have an inherent additional uncertainty due to adding the uncertainties in the gas ratios to the original SOF flux estimate uncertainty. The variability of the result is a combination of measurement uncertainties and actual variability in the emissions generated by these sites. Anomalous emission values, observed in a few occasions/days for some of the facilities, were not excluded since site operations at the time of measurements were unknown and, hence, these values may very well represent a part of the standard operations.

Table 33. Measured and scaled-up emissions for the total SCAB per source category, based on FluxSense measurements during the SCAQMD-2015 campaign, Projects 1 and 2.

Source Category Project-2	**No. of Meas. Units**	**Estimated Number of units in the SCAB**	**Measured Alkane Emissions** [kg/h]	**Scaled-up Alkanes Emissions** [kg/h]	**Scaled-up BTEX† Emissions** [kg/h]	**Scaled-up Benzene† Emissions** [kg/h]	**Scaled-up CH_4† Emissions** [kg/h]
Oil & Gas Wells	106	5000*	138	6510	487	75	1568
Tank Farms, Terminals & Depots	328	750**	314	718	59	7.3	560
Petroleum Treatment Sites & Small Refineries	9	15**	501	835	48	12	411
Gas Stations	8	3140*	10	1947	488	52	492
Offshore Facilities & Activities	7	20**	69	196	*n.m.*	*n.m.*	*n.m.*
Other Sources	7	Unknown	286	286	*n.m.*	*n.m.*	109
Uncategorized Area Source	1	Unknown	483	483	*n.m.*	*n.m.*	301
Six Large Refineries (Project-1)	6	6	1130	1130	129	18	705
Total SCAB	**472**	**8932**	**2931**	**12105**	**1212**	**164**	**4146**

†Median BTEX and CH_4 fractions within each category have been used to calculate scaled-up fluxes. Also shown are the results for six large refineries (Project-1), which are described in separate report. *[DOGGR 2016] ** Visual Estimations using GoogleEarth™. n.m. = not measured.

Table 33 presents a summary of the measured and estimated scaled-up total hourly emission rates for all different categories in this study and in Project-1. The total measured emission of alkanes from all sources in Project-2 adds up to 1,318 kg/h, which is comparable to the 1,130 kg/h from the six large refineries in Project-1. There is also a contribution of 483 kg/h from the Uncategorized Area Source, resulting in a total measured alkane emission rate of 1801 kg/h. During Project 2 emission measurement were conducted from a very limited subset of small sources, while in Project 1 emissions from nearly all big refineries where quantified. When extrapolated to the total number of estimated small sources in the SCAB, the total hourly alkane emissions add up to around 12,000 kg/h, most of which (over 85 %) emanated from the six source categories considered in Project-2.

Figure 36 shows the relative distribution of alkane+BTEX emissions if the average results from the measured units within each category in Table 33 are used to scale total emission fluxes for all measured types of sources. This gives an overall alkane+BTEX emission of approximately 13,000 kg/h of which 53% from *Oil & Gas Wells*, 18% from *Gas Stations*, 9% from *Large Refineries (Project-1)*, 7% from *Treatment Facilities & Small Refineries*, 6% from *Tank Farms, Terminals & Depots*, and 2% from *Other Sources*. *Off Shore Facilities & Activities* emissions represent only about 1% of the total. However we are of the opinion that the overall emissions from this last source category are higher than calculated if one were to account for oil platform emissions and fuel barge operations which are not included in the Project 2 survey. The category distribution for individual gases (alkanes, BTEX, Benzene and Methane) are found in Figure 37 to
Figure 40. Notable here are the high relative contribution of *Gas stations* for BTEX (40%) and *Oil & Gas Wells* for Methane (38%).

The scaling-up approach has uncertainties due to the assumptions made on the total number of units for each source category. Measurements may also not be representative for all times of the day and seasons (e.g., gas stations tend to be busier during rush hour when most measurements were made). Ideally, the gas station measurements should be assessed relative to the actual loading volumes, establishing an emission factor that can be scaled to the overall gas station loading volumes in the SCAB. On average, there were 4.6 cars fuelling while the gas station measurements were conducted in this project. The gas station measurements include the overall fuelling event, for example lining up prior to accessing the fuel pump, actual fuelling and then starting up to leave the site. In the present scaling for the gas station emissions, a diurnal cycle was used with the established average emission applied for 12 hours, and no emissions for the remaining time.

In terms of scaling emissions to estimate emissions from all offshore activities, there is a large uncertainty in, for example, the average number of active fuel barge operations, ship fuelling and venting activities. For this purpose, a more viable approach would be to include more measurements to establish typical emission factors for these activities and scale with data on number of operations within the port area, or handled product volumes where applicable.

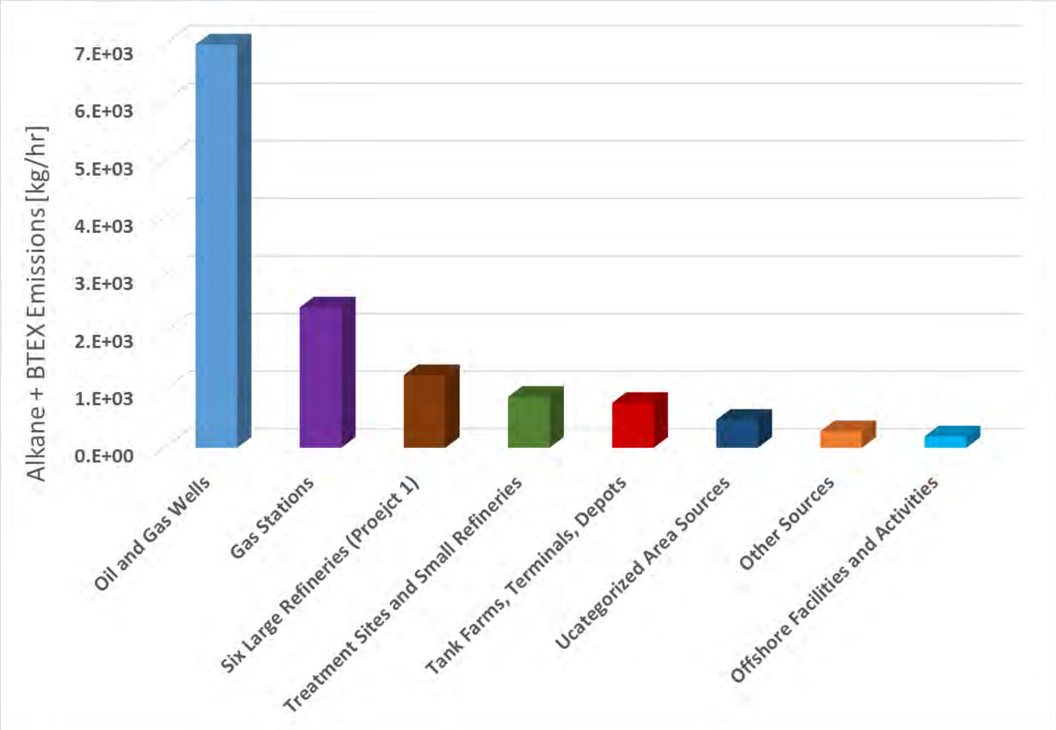

Figure 36. Relative contribution to total **alkane and BTEX** emissions from the various source categories investigated in Projects 1 and 2. Emission rates for each category were calculated by multiplying the average measured emission per unit by the estimated number of total units. Total alkane and BTEX emissions are approximately 13,000 kg/h from all included sources. Note that no BTEX emissions are excluded for *Offshore Facilities*, *Other Sources* or for the *Uncategorized Area Source,* due to lack of measurements.

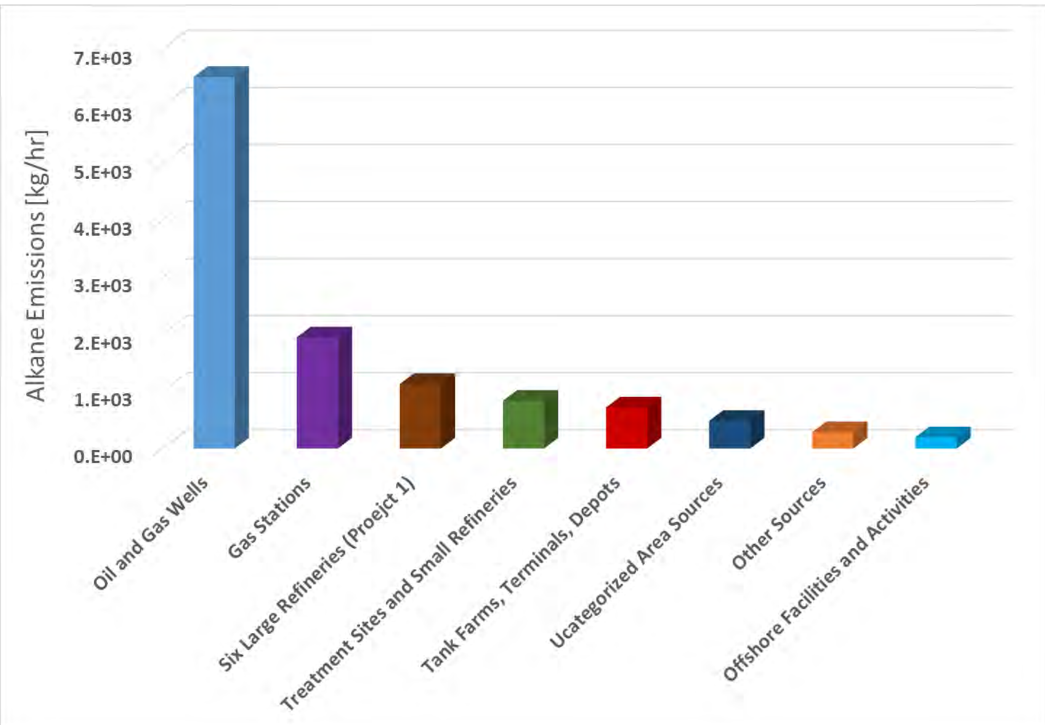

Figure 37. Relative contribution to total **alkane** emissions from the various source categories investigated in Projects 1 and 2. Emission rates for each category were calculated by multiplying the average measured emission per unit by the estimated number of total units. Total alkane emissions are approximately 12,000 kg/h from all included sources.

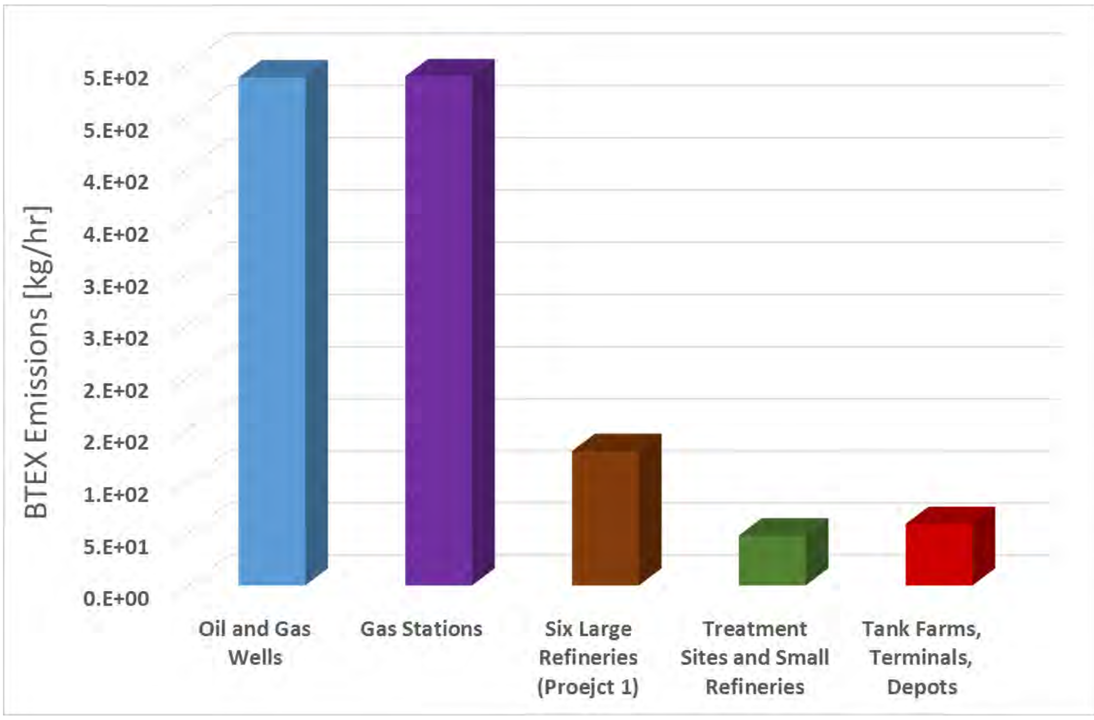

Figure 38. Relative contribution to total **BTEX** emissions from the various source categories investigated in Projects 1 and 2. Emission rates for each category were calculated by multiplying the average measured emission per unit by the estimated number of total units. Total BTEX emissions are approximately 1,200 kg/h from all included sources. Note that BTEX emissions were not included for *Offshore Facilities*, *Other Sources* or for the *Uncategorized Area Source,* due to lack of measurements.

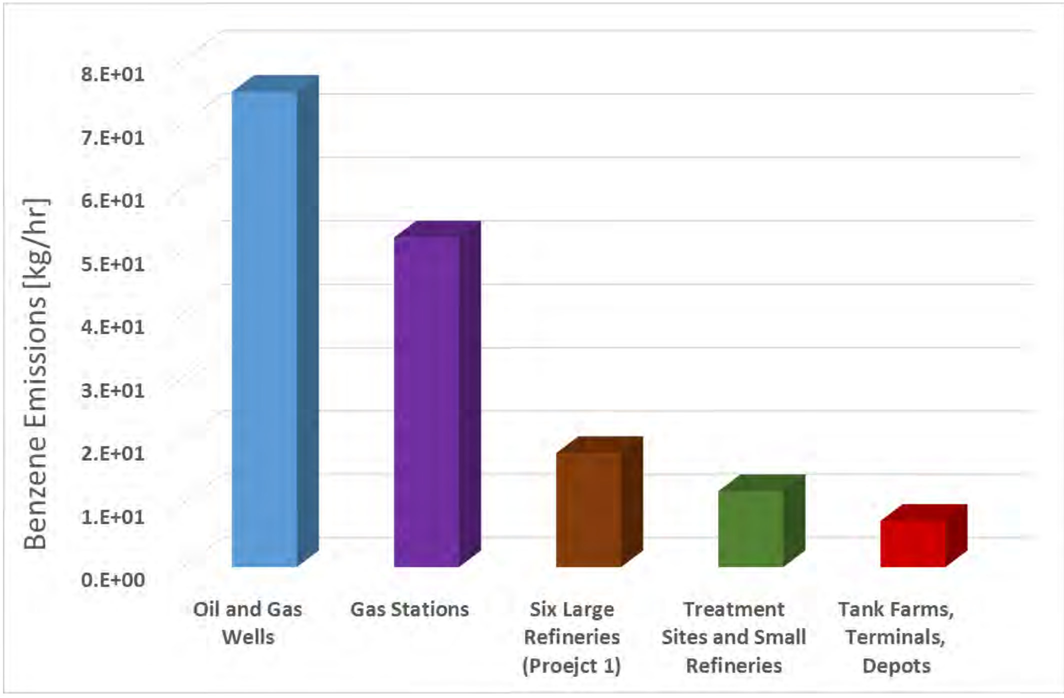

Figure 39. Relative contribution to total **benzene** emissions from the various source categories investigated in Projects 1 and 2. Emission rates for each category were calculated by multiplying the average measured emission per unit by the estimated number of total units. Total benzene emissions are approximately 160 kg/h from all included sources. Note that Benzene emissions from *Offshore Facilities*, *Other Sources* or for the *Uncategorized Area Source* were not included due to lack of measurements.

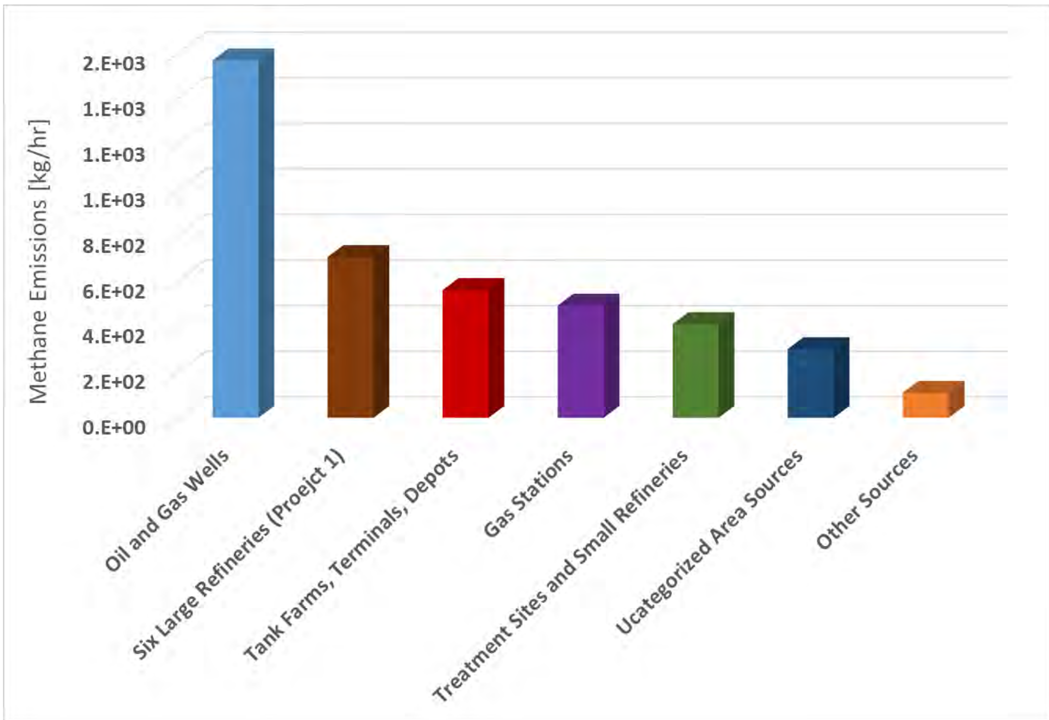

Figure 40. Relative contribution to total **methane** emissions from the various source categories investigated in Projects 1 and 2. Emission rates for each category were calculated by multiplying the average measured emission per unit by the estimated number of total units. Total methane emissions are approximately 4,100 kg/h from all included sources. Note that methane emissions from *Offshore Facilities* were not included due to lack of measurements.

Considerable methane emissions were seen from the various sources in Project-2. The average measured methane to alkanes ratio for the oil and gas wells was 0.53, whereas a much higher value (0.78) was measured for tank farms and depots. Aside from methane being part of the stored or handled product, the presence of methane emissions could be explained common practices such as when tanks are blanked with methane at the top to limit VOC emissions, and methane is leaking into the atmosphere. The overall methane emission rate of 636 kg/h was calculated from the selected sites investigated in Project-2. This value is comparable to the emission rate measured from the large refineries in Project-1 (700 kg/h). However, when emissions measured in Project 2 are scaled-up to account for other small sources in the SCAB, methane emissions from these non-refinery sources become dominant.

Approximately 68 kg/h of BTEX (of which 12 kg/h was benzene) were measured from the various sources surveyed in this project. These emission rates are approximately half of the total BTEX rates measured from all large refineries in the SCAB (see Project 1). Considering the large number of active oil wells and gas stations in the SCAB, the total actual BTEX load from these sources is likely to be substantial.

Large temporal variations in measured emission rates and large variability in emissions from similar sources/sites/units were also observed. This variability highlights the importance to associate the amounts of observed emissions with the type(s) of operations conducted at each site. The drilling event observed on October 15, 2015 (see Section 4.1.1) offers a good example of how emissions can vary over the life cycle of an oil well. More detailed information on the status of each unit and of ongoing activities at each sites will provide useful information on when large emissions may occur and how they could be reduced.

Measured average emissions from the *Uncategorized Area Source* in Carson/Wilmington were 483 kg/h of alkanes and 301 kg/h of methane. Daily measured emissions showed significant variability, with values ranging from over 700 kg/h on 3 September 2015 to less than half this amount for the remaining measurement days (see Table 29). A more detailed survey of this area was not possible due to the complexity of the fence-line configuration and the variable wind patterns experienced during the study. Additional measurements in this area, preferably during easterly winds, could help assign the emissions to the specific sites. If such source identification is successful, emissions from the different sites can be assigned to the appropriate source category, creating a more accurate total emission estimate. BTEX measurements in this area will also help to create a more complete picture of emissions.

Substantial methane and ammonia emissions were measured from *cattle farms* in Chino. On average 245 kg/h NH_3 and 540 kg/h CH_4 (compared to 648 kg/h from the other measured sources) were observed from an area of 5.4 by 4.0 km, including approximately 17 cattle farms. No attempt was made to scale-up these biogenic emissions of NH_3 and CH_4, because of the limited number of measurements taken, the limited knowledge of the sources, and the total number of units (cattle farms or cows) in the SCAB. More extensive measurements are needed to better quantify emissions from this source category and from other biogenic sources such as water treatment plants or landfills.

This project also demonstrated the potential of mobile measurements for community-scale monitoring. Traditionally, such monitoring is conducted by establishing multiple fixed measurement sites near the facility of interest and in a surrounding community. While this strategy is sufficient for surveying emissions from a single facilities, it is nearly impossible to implement for routine community scale monitoring at numerous locations. Therefore, mobile measurements offer a clear progress towards large-scale monitoring of multiple sources and communities.

6 Acknowledgements

This work was funded by the South Coast Air Quality Management District (SCAQMD). We would like to acknowledge the important contributions by Dr. Laki Tisopulos, Dr. Andrea Polidori, Dr. Olga Pikelnaya and other SCAQMD staff.

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8 Appendix: Quality Assurance

Quality checks and measures are performed at several levels in order as indicated in Figure 2 and given below. On arrival on a measurement day, FluxSense personnel will power up the equipment, check operating parameters, and test the instruments. The purpose is to run operational checks to catch problems prior to field deployment and repair all malfunctioning equipment.

Quality Checks and Routines

PRIOR TO MEASUREMENTS:

Vehicle:

1. Checking vehicle status according to safety and performance
2. Mount warning lights and signs
3. Make sure that battery pack is fully charged
4. Make sure any loose items are stowed away securely

Instruments:

1. Turn on instruments and make sure that detectors are properly cooled
2. Optimize signals by optical alignment (SOF, SkyDOAS, MWDOAS, MeFTIR)
3. Cleaning mirrors and optics if necessary (SOF, SkyDOAS, MWDOAS)
4. Rotational alignment (SOF). Tolerance: ±2 mg/m^2 in any direction
5. Checking spectral resolution and response (SOF, SkyDOAS, MWDOAS, MeFTIR)
6. Take calibration spectra (SkyDOAS, MWDOAS)

GPS:

1. Checking that GPS information is available and reasonable.
2. Check time synchronization of all instruments and computers.

Wind:

1. Checking that the time difference of logger and computer and synchronize if necessary. Tolerance 1s.
2. Select an open flat surface at a representative location for the measurements
3. Erecting the wind mast vertically and secure it firmly
4. Directing sensor correctly (toward magnetic north) using a compass. Tolerance: ±5 deg.
5. Check that wind information is available and reasonable

Tracer Measurements:

1. Weigh gas tube without regulator and ensure sufficient amount of trace gas left for the entire measurement period
2. Mount gas regulator and release tube and ensure no leaks.
3. Turn the gas regulator to an appropriate flow rate for the prevailing measurement conditions and note start time.

DURING MEASUREMENTS:

1. Drive slowly and steadily to reduce vibration noise. Around 20-30 km/h for SOF/SkyDOAS and around 10-20 km/h for MWDOAS/MeFTIR (dependent on distance to source and the spatial resolution required)
2. Avoid shadows as far as possible during solar measurements (SOF, SkyDOAS).
3. Try boxing the facilities when possible or make relevant upwind/background measurements continuously.
4. Keep track of wind directions and measured columns/concentrations so that the entire plume from a facility is captured.
5. Always try to start new measurements outside the plume.
6. Aim for 3-5 transects with acceptable quality (See section on data analysis below) per facility and day and at least 1 upwind measurement (if not boxing).
7. Take notes and photos on interesting findings and events
8. Check the wind meter on a regular basis to make sure that it is operational

AFTER MEASUREMENTS:

1. Turn off instruments and download gas measurement data to external hard drive
2. Download data from wind mast logger and save to external hard drive
3. Download data from wind LIDAR and save to external hard drive
4. Dismount wind mast if not in safe location
5. Turn off wind LIDAR and store securely over night
6. Store Airmar data and measurement notes on external hard drive
7. Update survey documents and Google Earth maps accordingly
8. Charge vehicle, LIDAR and data logger batteries over night
9. Make sure that instruments are well protected inside the vehicle from rain/moisture

For Tracer Measurements:

10. Turn off gas regulator and note stop time.
11. Dismount regulator and weigh gas tube

DATA ANALYSIS:

1. Discard transects with noise levels above the detection limits (see Table 1)
2. Discard transects with significant baseline variations
3. Discard transects with significant data gaps in the plume
4. Discard transects with extended vehicle stops
5. If incoming plumes are of significant magnitude compared to the outgoing plume (SOF and SkyDOAS) treat transects with extra care and require further statistics
6. Discard transects with average wind speeds below 1.5 m/s (SOF and SkyDOAS)
7. Discard transects with highly varying wind directions
8. Discard transects with no relevant wind information or opposing results for nearby met stations.

Data Analysis, Interpretation, and Management

DATA REPORTING REQUIREMENTS:

A Draft and Final Report are delivered to SCAQMD electronically (i.e., via file transfer protocol (FTP) or e-mail) in MS-WORD. Raw data and a Google Earth-KMZ file with geo location information of the sites will be delivered to SCAQMD at the time of the final report.

DATA VALIDATION PROCEDURES:

FluxSense maintain records that include sufficient information to reconstruct each final reported measurement from the variables originally gathered in the measurement process. This includes, but is not limited to, information (raw data, electronic files, and/or hard copy printouts) related to sampler calibration, sample collection, measurement instrument calibration, quality control checks of sampling or measurement equipment, "as collected" or “raw” measurement values, an audit trail for any modifications made to the "as collected" or “raw” measurement values, and traceability documentation for reference standards.

Difficulties encountered during sampling or analysis, such as interference between adjacent plumes, large upwind fluxes or highly variable wind fields are documented in narratives that clearly indicate the affected measurements. All electronic versions of data sets should reflect the limitations associated with individual measurement values.

The data collected in the project is made available in electronic format at the time of the final report. For all data we will produce ASCII tables with the geo-positioning and time. In addition, KMZ files will be produced for the most useful data for Google Earth viewing.

To ensure high quality data an internal audit procedure of the data is carried out. In the project, gas columns obtained from SOF and mobile DOAS measurements are used to calculate gas fluxes through a procedure which includes manual checking of each measurement transect and manual choices of baselines etc. In the audit procedure the completed transects will be reviewed by a person that was not involved in the actual data evaluation.

STATISTICAL PROCEDURES:

The final data is presented as daily averages and standard deviations for each facility together and a total survey averages. Note that the variability of the result is a combination of measurement uncertainties, wind variability and actual variability in the emissions from the facilities.

Extreme outliers are generally not excluded, unless non-typical conditions/operations at the site are reported. In this case, the outliers are reported separately so that these conditions/operations can be followed up.

More samples provide a closer estimate of the actual emissions. In reality, the number of measurements will be a trade-off between acceptable statistics and available time and conditions for making the measurement and time sharing between other measurements.

DATA SUMMARY AND ANALYSIS:

The data is post processed with the spectral retrieval programs QESOF (SOF) and QDOAS (mobile DOAS). This gives time series of column concentrations, positions and solar angles stored in ASCII-files. These files are loaded into custom software, SOF-Report, used to calculate fluxes.

Wind LIDAR data are processed using the output from Leosphere WindCube system. Data files are saved as ASCII-files.

The weather mast is connected to a real time data logger and is periodically downloaded to a computer. The data logger samples the input voltage of each instrument at a set time interval, digitizes it, and stores the data sequentially into a record.

ASCII tables with time stamped geo positioned data are produced. In addition, kml files will be produced for viewing the data in Google Earth. The data will also be retained for a minimum of 5 years at FluxSense.

DATA STORAGE REQUIREMENTS:

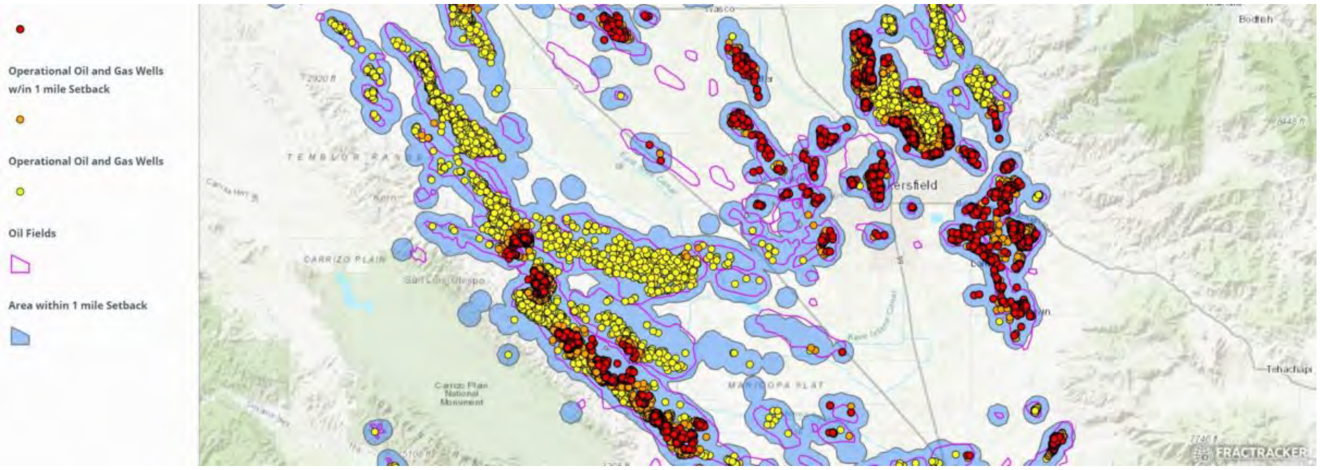
The spectra from the spectroscopic measurements (SOF, SkyDOAS, MeFTIR, MWDOAS) are directly saved to the hard drive of the computer used to operate these instruments. At the end of each measurement day, all new such data will be copied to an external hard drive by the operator. Approximately 1 GB of data will be produced per measurements day.

People and Production: Reducing Risk in California Extraction

fractracker.org/2020/12/people-and-production/

Kyle Ferrar, MPH

December 17, 2020



Executive Summary

New research shows that low-income communities and communities of color that are most impacted by oil and gas extraction (Frontline Communities) in California are at an elevated risk for preterm birth, low birth weight, and other negative birth outcomes. This is in addition to the elevated risks of cancer; risks for respiratory, cardiovascular, and pulmonary disorders; and risks for eyes, ears, nose, throat, and skin irritation that Frontline Communities face, among others. Public health interventions including setback requirements for oil and gas drilling are necessary to address the environmental health endemics documented in Frontline Communities.

This report focuses on the two immediate stakeholders impacted by oil and gas well drilling setbacks: Frontline Communities and oil and gas operators. First, using U.S. Census data this report helps to define the Frontline Communities most impacted by oil and gas extraction. Then, using GIS techniques and California state data, this report estimates the potential impact of a setback on California's oil production. Results and conclusions of these analyses are outlined below.

- Previous statewide and regional analyses on proximity of oil and gas extraction to various demographics, including analyses included in Kern County's 2020 draft EIR, have inadequately investigated disparate impacts, and have published erroneous results.
- This analysis shows that approximately 2.17 million Californians live within 2,500' of an operational oil and gas well, and about 7.37 million Californians live within 1 mile.
- California's Frontline Communities living closest to oil and gas extraction sites with high densities of wells are predominantly low income households with non-white and Latinx demographics.
- The majority of oil and gas wells are located in environmental justice communities most impacted by contaminated groundwater and air quality degradation resulting from oil and gas extraction, with high risks of low-birth weight pregnancy outcomes.
- Adequate Setbacks for permitting new oil and gas wells will reduce health risks for Frontline Communities.
- Setbacks for permitting *new* oil and gas wells will not decrease existing California oil and gas production.
- Phasing out wells within setback distances will further decrease health risks for Frontline Communities.
- Phasing out wells by disallowing rework permits within a 2,500' setback distance will have a minimal impact on overall statewide oil production, estimated at an annual maximum loss of 1% by volume.
- Setbacks greater than 2,500' in combination with other public health interventions are necessary to reduce risk for Frontline Communities.
- Based on the peer reviewed literature, a setback of at least one mile is recommended.

Table of Contents

Introduction

The energy focused on instituting policies to protect the health of Frontline Communities in California from the negative impacts of oil and gas extraction is at an all-time high. In August 2020, Assembly Bill 345 was heard in the State Senate's Natural Resources Committee, but was blocked from reaching the Senate floor for a vote. The bill would have required the Geologic Energy Management Division in the Department of Conservation (CalGEM) to establish a minimum setback distance between oil and gas production and related activities and sensitive receptors like homes, schools, and hospitals. While this strong effort to establish health and safety setbacks through the state legislature may have failed, the movement has paved the way for local actions. Additionally, California is in the midst of a statewide public health rule-making process to address the health impacts of oil and gas extraction currently experienced by Frontline Communities.

In related advocacy, Frontline Community groups in California recommended a minimum 2500' setback based on scientific studies, including a 2015 report by the California Council on Science and Technology which identified "significant" health risks at a distance of one-half mile from drill sites. A recent grand jury report from Pennsylvania recommended 5,000' setbacks, with 2,500' as a minimum requirement to address the most impacted communities. Additionally, the state of Colorado has recently adopted 2,000' setbacks for homes and schools, while the existing 2,000' setback has had minimal impacts on oil and gas production.

In September 2020, Governor Newsom declared the deadline for the first draft of the pre-regulatory rule-making report will be the first of January 2021. FracTracker Alliance has therefore completed an updated assessment of the Frontline Communities most impacted by oil and has projected the potential impact on oil and gas extraction operations. An interactive map of oil and gas activity and Frontline Communities is shown below in Figure 1. The map identifies the operational (active, idle, and new) oil and gas wells located within 2,500' and 1 mile buffer zones from sensitive receptors, defined as homes, schools, licensed daycares and healthcare facilities.

The impacts of oil and gas drilling do not stop at 2,500', as regional groundwater contamination and air quality degradation of ozone creation and PM2.5 concentrations are widespread hazards of oil and gas extraction. Phasing out wells within 2,500' of homes will reduce the negative health effects for the Frontline Communities bearing the brunt of the risks associated with living near oil and gas wells, as well as reduce regional environmental hazards. These risks include over 24 categories of health impacts and symptoms associated with 14 bodily systems, including eyes, ears, nose, and throat; mental health; reproduction and pregnancy; endocrine; respiratory; cardiovascular and pulmonary; blood and immune system; kidneys and urinary system; general health; sexual health; and physical health among others. The most regularly documented health outcomes include mortality, asthma and respiratory outcomes, cancer risk including hematological (blood) cancer, preterm birth, low birth weight and other negative birth outcomes.

The interactive map below in Figure 1 shows the operational oil and gas wells located within 2,500' of sensitive receptors, including homes, schools, healthcare facilities, prisons, and permitted daycares. Overall in the state of California, 16,724 operational (8,618 active, 7,786 idle, and 320 new) wells are located within the 2,500' setback. Of the total ~105,000 operational (62,000 active, 37,400 idle, and 6,000 new), about 16% are within the setback. These wells accounted for 12.8% of the total oil/condensate produced in California in 2019. Table 1 below shows the counties where these wells are located, by well permit status. It bears noting that these figures on well location and production represent only a snapshot of current industry activity. As discussed below, current setback proposals would provide a phase out period for existing wells that would greatly reduce any immediate impact on production. Further, directional and even horizontal drilling is common in California, meaning operators can relocate their surface drilling equipment to safer distances and still access oil and gas reserves to maintain production.

Table 1. Status of wells within the 2,500' setback zone, by county. The table shows the counts of wells located within the 2,500' setback from homes and other sensitive receptors, broken out by the status of the wells.

	Well Count by Status		
County	Active	New	Idle
Kern	3,501	234	2,171
Los Angeles	2,580	29	3,006
Orange	914	13	816
Ventura	534	7	600
Santa Barbara	198	17	241
Los Angeles Offshore	168	2	51
Glenn	133		76
San Joaquin	97		71
Monterey	88	9	95
Fresno	86	6	137
Sutter	73		71

Tulare	65	1	30
Colusa	47		80
Tehama	38		34
Solano	30	0	65
Sacramento	22	1	38
San Bernardino	14		29
Humboldt	12		11
Alameda	7		3
Contra Costa	5	1	16
San Benito	3		4
San Luis Obispo	2		14
Yolo	1		13
Grand Total	8,618	320	7,786

View map fullscreen

Figure 1. Map of California operational oil and gas wells with 2,500’ and one mile setback distances. One mile setbacks are included as a minimum recommendation of this report based on peer reviewed literature. This report recommends the state of California consider one mile as a minimum setback distance to protect Frontline Communities. As you zoom into the map additional, more detailed layers will appear.

Methods (Quick Overview)

In this article we conducted spatial analyses using both the demographics of Frontline Communities and the amount of oil produced from wells near Frontline Communities. This assessment used CalGEM data (updated 10/1/20) to map the locations of operational oil and gas wells and permits, as shown above in Figure 1. The analyses of oil production data utilized CalGEM’s annual production data reporting barrels of oil/condensate. GIS analyses were completed using ESRI ArcGIs Pro Ver. 2.6.1 with data projected in NAD83 California Teale Albers.

Wells within 2,500’ and 1 mile of sensitive receptors were determined using GIS techniques. This report defines sensitive receptors as residences, schools, licensed child daycare centers, healthcare facilities. Sensitive receptor datasets were downloaded from California Health and Human Services, and the California Department of Education.

We used block group level “census designated areas” from American Community Survey (2013-2018) demographics to estimate counts of Californians living near oil and gas extraction activity. Census block groups were clipped using the buffered datasets of operational oil and gas wells. A uniform population distribution within the census blocks was assumed in order to determine the population counts of block groups within 2,500’ of an operational oil and gas well, 2,500’ to 1 mile from an operational well, and beyond 1 mile from an operational well. Census demographics and total population counts were scaled using the proportion of the clipped block groups within the setback area (Areal percentage = Area of block group within [2,500’; 2,500’-1 mile; Beyond 1 mile] of an operational well / Total area of block group).

This conservative approach provided a general overview of the count and demographics of Californians living near extraction operations, but does little to shed light on most impacted Frontline Communities; specifically urban areas with dense populations near large oil fields. More granular analyses at the local level were necessary to address the spatial bias resulting from non-uniform census block group dimensions and population density distributions, as well as the distribution of operational oil and gas wells within the census block groups. Consequently, we conducted further analysis utilizing customized sample areas for each oil field, which were selected manually using remote sensing data. Full census blocks were used to summarize the actual areas and the urban populations constituting the majority of Frontline Communities.

In the localized, static maps that follow, the census blocks included in the population summaries are shown in pink, while the surrounding census blocks are shown in blue. As seen in Table 2, census data for this initial environmental justice assessment was limited to "Race" (Census Table XO2), "Hispanic or Latino Origin" (Census Table XO3) and several other indicators including "Annual Median Income of Households" (Census Table X19) and "Poverty" (Census Table X17).

Results and Discussion

California Statewide Analysis

Demographics

As a baseline, it is important to provide statewide estimations to track the total number of Californians living near oil and gas extraction operations. This analysis showed that about 2.17 million Californians live within 2,500' of an operational oil and gas well, and about 7.37 million Californians live within 1 mile. The demographics of these communities at and between these distances is shown below in Table 2, alongside demographic estimates of the California population living beyond 1 mile from an oil and gas well. Census block groups closer to oil and gas wells have higher proportions of Non-white (calculated by subtracting "White Only" from "Total Population") and Latinx ("Hispanic or Latino Origin") populations, as well as higher proportions of low-income households, based on both median annual income and poverty thresholds. The analysis show that communities living closer to oil and gas wells have higher percentages of non-white and Latinx populations when compared to the population living beyond 1 mile from an operational oil and gas wells. Communities closer to oil and gas wells are also more likely to be closer to the poverty threshold with lower median annual household incomes.

Table 2. The table shows statewide demographics at multiple distances from operational oil and gas wells. Included are estimates of the non-white and Latinx proportions of the populations within set distances from operational oil and gas wells. The percentage of populations within several poverty thresholds were also summarized, along with median annual household income and age.

	Distance from an operational oil and gas well		
Indicators of Disparity	Within 2,500′	2,500′ – 1 Mile	Beyond 1 Mile (Statewide)
Demographics: Non-white	44.44%	43.56%	39.16%
Demographics: Latinx	43.25%	44.97%	37.79%
Poverty: Under Poverty Threshold	15.01%	14.97%	14.12%
Poverty: Under 1.5X Poverty Threshold	24.31%	24.85%	23.25%
Poverty: Under 2X Poverty Threshold	33.59%	34.25%	32.17%
Median Annual Household Income < $40k	30.09%	30.73%	28.72%

Median Annual Household Income <$75k	53.53%	54.36%	51.76%
Age: 0-5 years	6.08%	6.12%	6.37%
Age: <18 years	21.54%	22.12%	23.39%
Age: 65+	13.17%	13.11%	13.68%
Demographics: White only	55.56%	56.44%	60.84%

CalEnviroScreen

CalGEM operational wells data was also overlaid on CalEnviroScreen 3.0 (CES) indicators of environmental health. CES is provided by the Office of Environmental Health Hazard Assessment (OEHHA), on behalf of the California Environmental Protection Agency (CalEPA).

CalEnviroScreen data, like U.S. Census data, is also aggregated at the census block group level. While this data can also suffer from the same spatial bias as the statewide analysis above, CES is still very useful to visualize and map the regional pollution burden to assess disparate impacts. The results of the analysis are shown below in Table 3. Counts of operational oil and gas wells for ranges of CES percentile scores. Higher percentiles represent increased environmental degradation or negative health impacts as specified. Of note, the majority of operational oil and gas wells are located in census tracts with the worst scores for air quality degradation and high incidence of low birth weight.

The large number of wells located in the 60-80th percentile rather than the worst (80-100th percentile) is a result of spatial bias, and the many factors that are aggregated to generate the CES Total Scores. These factors include relative affluence and other indicators of socio-economic status. The majority of the worst (80th-100 percentile for Total CES Score) census block groups are located in low-income urban census block groups, many in Northern California cities that do not host urban drilling operations.

This spatial bias results from edge effects of census block groups, where communities living near oil and gas extraction operations may not live in the same census block groups as the oil and gas wells, and are therefore not counted. The authors would recommend future analyses be designed that use CES data to assess disparate impacts in the census block groups most impacted by oil and gas extraction. Neighboring census block groups that do not physically contain operational wells still suffer the consequences of proximity.

For the asthma rankings, the majority of wells are located in the best CES 3.0 percentile (0-20th percentile) for Asthma. While there is much urban drilling in Los Angeles, the spatial bias in this type of analysis gives more weight to the majority of oil and gas wells that are located in rural areas, which historically have much lower asthma rates. This is a result of the very high incidence of asthma in cities without urban drilling such as the Bay Area and Sacramento (80-100th percentile).

Table 3. Counts of operational oil and gas wells in select CalEnviroScreen 3.0 indicators census tracts.

	Operational Well Counts by CES3.0 Percentile				
	0-20%ile	20-40%ile	40-60%ile	60-80%ile	80-100%ile
PM2.5 Air Quality Degradation	5,708	4,237	16,614	7,089	69,987
Ozone Air Quality Degradation	2,238	5,435	6,107	9,898	79,957
Contaminated Drinking Water	1,019	1,675	53,452	6,214	41,206

High Incidence of Low Birth Weight	10,186	13,368	14,995	3,236	58,036
High Incidence of Asthma	40,247	19,827	18,902	4,867	19,792
Total CES 3.0	1,583	5,756	15,671	65,356	12,985

Spatial Bias

Using census data to assess the demographics of those communities most affected by oil and gas drilling can produce misleading results both because of how census designated areas (census tracts and block groups) are designed and because of the uneven distribution of residents within tracts. For example, the majority of Californians who live closest to high concentrations of oil and gas extraction, such as the Kern River oil field, do so in residentially zoned cities and urban settings. In most Frontline Communities the urban census designated areas do not actually contain many wellsites. Instead urban census designated areas are located next to the “estate” and “industrial” (including petroleum extraction) zoned census designated areas that contain the well-sites.

Estate and industrially zoned census designated areas contain the majority of well-sites in Kern County. They are much larger than residentially zoned areas with very low population densities and higher indicators of socioeconomic status. Population centers within the estate zoned areas are often located on the opposite end and farther from well sites than the lower income communities and communities of color living in the neighboring, residentially-zoned census designated areas (e.g., Lost Hills and Shafter). In these cases the statewide demographic summaries above misrepresent the Frontline Communities who are truly closest to extraction operations. Localized environmental justice demographics assessments can also be manipulated in this way.

For instance, The 2020 Kern County draft EIR (chapter 7 PDF pp. 1292-1305) used well counts aggregated by census tracts to conclude that wells in Kern County were not located in disparately impacted communities. Among other requirements for scientific integrity, the draft Kern EIR fails to take into account how the shape, size, and orientation of census designated areas affect the results of an environmental justice assessment. In addition, the EIR uses low-resolution data summarized at the census tract level. Census tracts are much too large to be used to investigate localized health impacts or disparities. Using these blatantly inadequate methods, the draft EIR even claimed Kern County’s oil and gas wells are predominantly located in higher income, white communities, which is outright wrong. For more specific criticisms of the Draft EIR read the FracTracker analysis of the 2020 Kern County EIR.

Results from these types of analyses can be very misleading. Using generalized methods of attributing wells to specific census designated areas does little to identify the communities most impacted by the localized environmental degradation resulting from oil and gas extraction operations, particularly when large census areas such as census tracts are used.

This report therefore takes a different approach, focusing directly on California’s most heavily drilled communities. To understand who and which communities are most harmed by the large-scale industrial oil and gas extraction operations in California, spatial analyses must be refined to focus individually on the communities closest to the highest density extraction operations. For the analyses below, census block groups within 2,500’ of ten different Frontline Communities, all located near some of California’s largest oil and gas fields, were manually identified. The selected block groups’ major population centers were all located within the 2,500’ buffers. Unlike the statewide analysis above, the localized analyses below do not assume homogenous population distributions. Using these methods, FracTracker has identified and demographically described some of the most vulnerable California communities most at risk to the impacts of oil and gas extraction. In the maps below, the “case” census block groups used to generate descriptive demographic summaries of at risk communities bordering extraction operations are outlined in pink, while surrounding census block groups are outlined in light blue.

Well Density

The analyses above are important to understand some of the public health risks of living near oil and gas drilling in California. Yet the methods above used statewide aggregation of well counts and static buffers that do not not show the spectrum of risk resulting from well density. Numerous Frontline Communities in California are within 1 mile or even 2,500’ of literally thousands of oil and gas wells. Conversely, there are many census areas in California that have been included within the spatial analysis of the full state, as described above, located near a single low producing well. Therefore the above methods conservatively summarize demographics and dilute the signal of disparate impacts for low income communities of color. Those methods are not able to differentiate between such scenarios as living near one low-producing well in the Beverly Hills golf course versus living in the middle of the Wilmington Oil Field.

As with any toxin, the dosage determines the intensity of the poison. In environmental sciences, increasing exposure to toxins by increasing the number of sources of a toxin can increase the dosage and therefore the severity of the health impact. The impact of well density has been documented in numerous epidemiological studies as a significant indicator of negative health outcomes, including recently published reports from Stanford University and The University of California – Berkeley linking adverse birth outcomes with living near oil and gas wells in California (Tran et. al 2020, Gonzalez et. al 2020). Therefore the rest of this report focuses on the Frontline Communities living near large oil extraction operations–i.e., oil fields with high densities of operational oil and gas wells.

Kern County

Toggle between the sections below by clicking in the upper left corner of the title bar.

Shafter

The City of Shafter, California, is located near more than 100 operational wells in the North Shafter oil field, as shown below in the map in Figure 2. Technically, the wells are located within a donut-shaped census block group (outlined in blue) that surrounds the limits of the urban census block groups (outlined in pink). Shafter's population of nearly 20,000 is over 86% Latinx, but the surrounding "donut" with just 2,000 people is about 70% Latinx, much wealthier, and with very low population density. The other neighboring rural census areas housing the rest of the Shafter oil field wells follow this same trend.

An uninformed analysis, such as the Kern County EIR, would conclude that the 2,000 individuals who live within the blue "donut" are at the highest risk, because they share the same census designated area as the wells. Notably, the only population center of this census block group (or census tracts, which follow this same trend) is at the opposite end of the block group, farthest from the Shafter oil field. Instead, the most at-risk community is the urban community of Shafter with high population density; the census block groups within the pink hole of the donut contain the communities and homes nearest the North Shafter field.

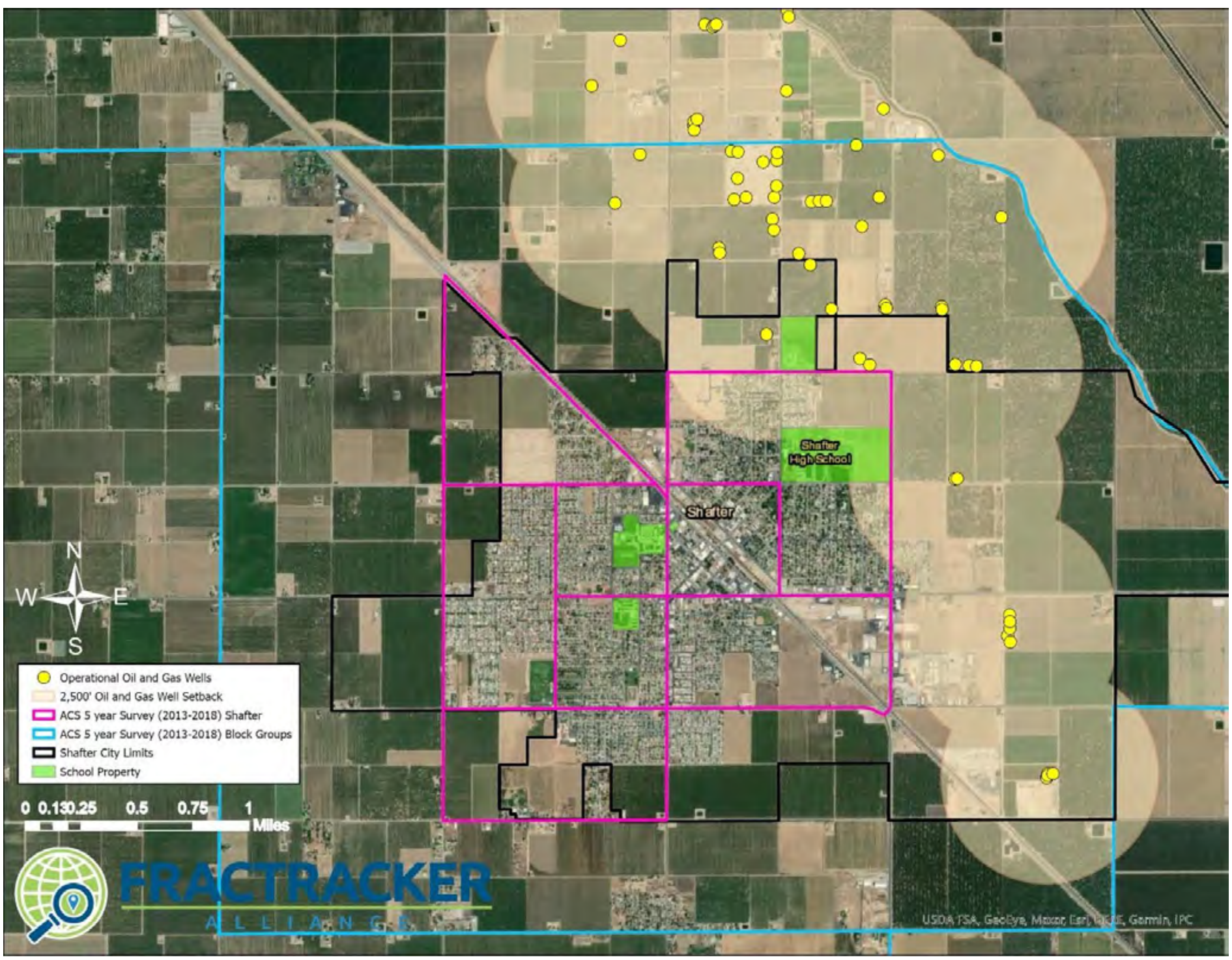


Figure 2. The City of Shafter, California is located just to the south of the North Shafter oil field. The map shows the 2,500’ setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Lost Hills, Arvin, & Taft

The cities of Lost Hills, Arvin, and Taft are all very similar to Shafter. The cities have densely populated urban centers located within or directly next to an oil field. In the maps below in Figures 3 readers can see the community of Lost Hills next to the Lost Hills oil field. Lost Hills, like the densely populated cities of Arvin and Taft, are located very close to large scale extraction operations. Census block groups that include the most impacted area of Lost Hills is outlined in pink, while surrounding low population density census block groups are shown in blue. The majority of the areas outlined in blue are zoned as “estate” and “agriculture” areas. The outlines of the city boundaries are also shown, along with 2,500’ and 1 mile setback distances from currently operational oil and gas wells.

Lost Hills is another situation where a donut-shaped census area distorts the results of low resolution demographics assessments, such as the one conducted by Kern County in their 2020 Draft EIR (PDF pp. 1292-1305). Almost all of the wells within the Lost Hills oil fields are just outside of a 2,500’ setback, but the incredibly high density of extraction operations results in the combined impact of the sum of these wells on degraded air quality. While stringent setback distances from oil and gas wells are a necessary component of environmental justice, a 2,500’ setback on its own is not enough to reduce exposures and risk for the Frontline Community of Lost Hills. For these Frontline Communities, a setback needs to be much larger to reduce exposures. In fact, limiting a public health intervention to a setback requirement alone is not sufficient to address the environmental health inequities in Lost Hills, Shafter, and other similar communities.

Lost Hill’s nearly 2,000 residents are over 99% Latinx, and over 70% of the households make less than $40,000 in annual income (which is substantially less than the annual median income of Kern County households [at $52,479]). The map in Figure 3 shows that the Lost Hills public elementary school is located within 2,500’ of the Lost Hills oil field and within two miles of more than 2,600 operational wells, in addition to the 6,000 operational wells in the rest of the field.

The City of Arvin has 8 operational oil and gas wells within the city limits, and another 71 operational wells within 2 miles. Arvin, with nearly 22,000 people, is over 90% Latinx, and over 60% of the households make less than $40,000 in annual income.

Additionally the City of Taft, located directly between the Buena Vista and Midway Sunset Fields, has a demographic profile with a Latinx population at least 10% higher than the rest of southern Kern County.

Lost Hills, Arvin, and Taft are among the most impacted densely populated areas of Kern County and represent the most Kern citizens at risk of exposure to air quality degradation from oil and gas extraction.

In all of these cases, if only census tract well counts are considered, like in the 2020 Kern County draft EIR, these Frontline Communities will be completely disregarded. Census tracts are intentionally drawn to separate urban/residential areas from industrial/estate/agricultural areas. The census areas that contain the oil fields are very large and sparsely populated, while neighboring census areas with dense population centers, such as these small cities, are most impacted by the oil and gas fields.

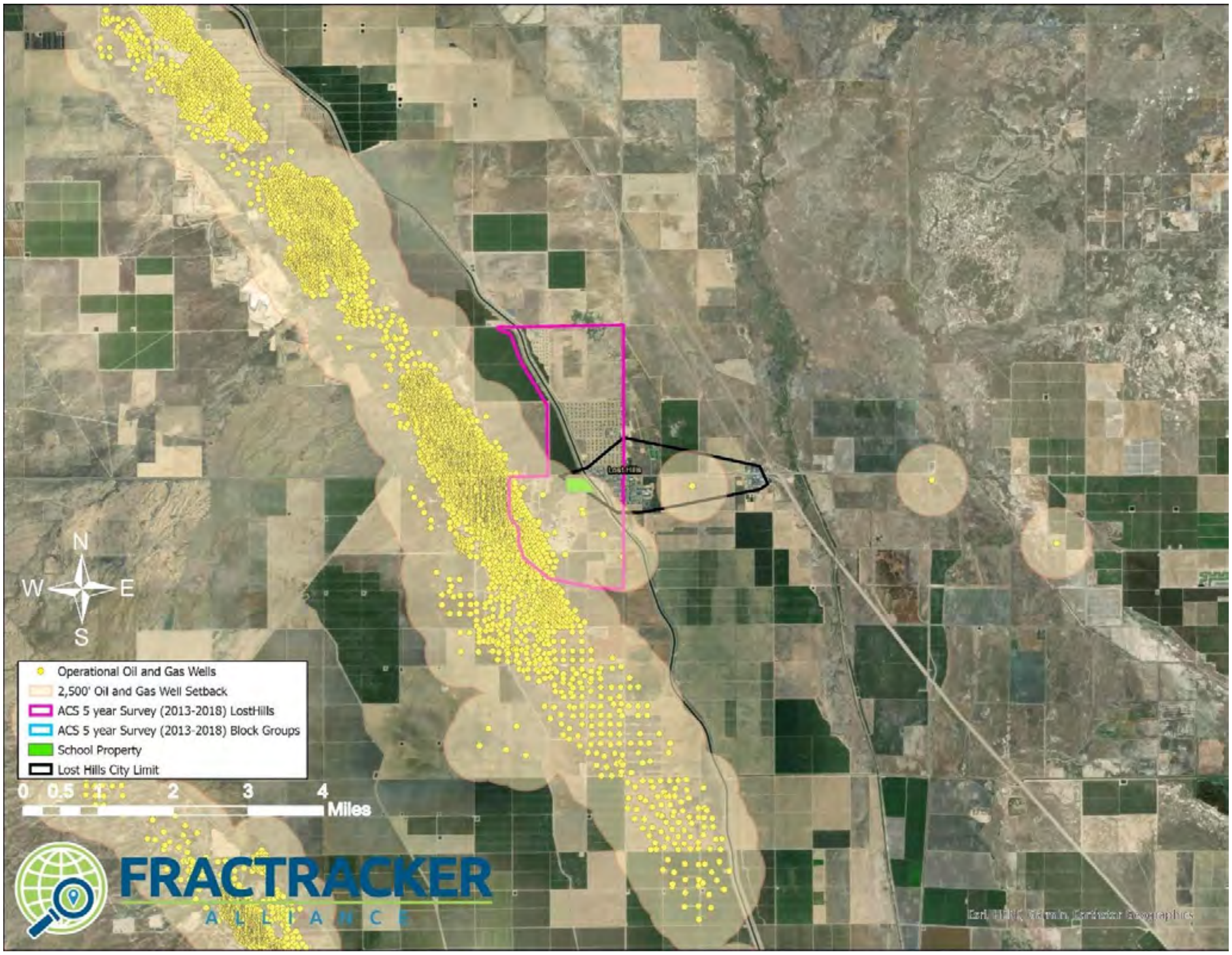


Figure 3. The Unincorporated City of Lost Hills in Kern County, California is located within 2,500' of the Lost Hills Oil Field. The map shows the 2,500' setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Bakersfield

The City of Bakersfield is a unique scenario. It is the largest city in Kern County and as a result suburban developments surround parts of the city. Urban flight has moved much of the wealth into these suburbs. The suburban sprawl has occurred in directions including North toward the Kern River oil field, predominantly on the field's western flank in Oildale and Seguro. In the map below in Figure 4, these areas are located just to the north of the Kern River.

This is a poignant example of the development of cheap land for housing developments in an area where oil and gas operations already existed; an issue that needs to be considered in the development of setbacks and public health interventions and policies. This small population of predominantly white, middle class neighborhoods shares similar risks as the lower-income Communities of Color who account for the majority of Bakersfield's urban center. Even though these suburban communities are less vulnerable to the oppressive forces of systemic racism, real estate markets will continue to prioritize cheap land for development, moving communities closer to extraction operations.

Regardless of the implications of urban sprawl and suburban development, it is important to no disregard the risks to the demographics of the at-risk areas of the city of Bakersfield are predominantly Non-white (31%) and Latinx (60%), particularly as compared to the city's suburbs (15% Non-white and 26% Latinx). About 33,000 people live in the city's northern suburbs, and another 470,000 live in Bakersfield's urban city center just to the south of the 16,500 operational wells in the Kern River, Front, and Bluff oil fields. The urban population of Bakersfield is a large Frontline Community exposed to the local and regional negative air quality impacts of the Kern River and numerous other surrounding oil fields.

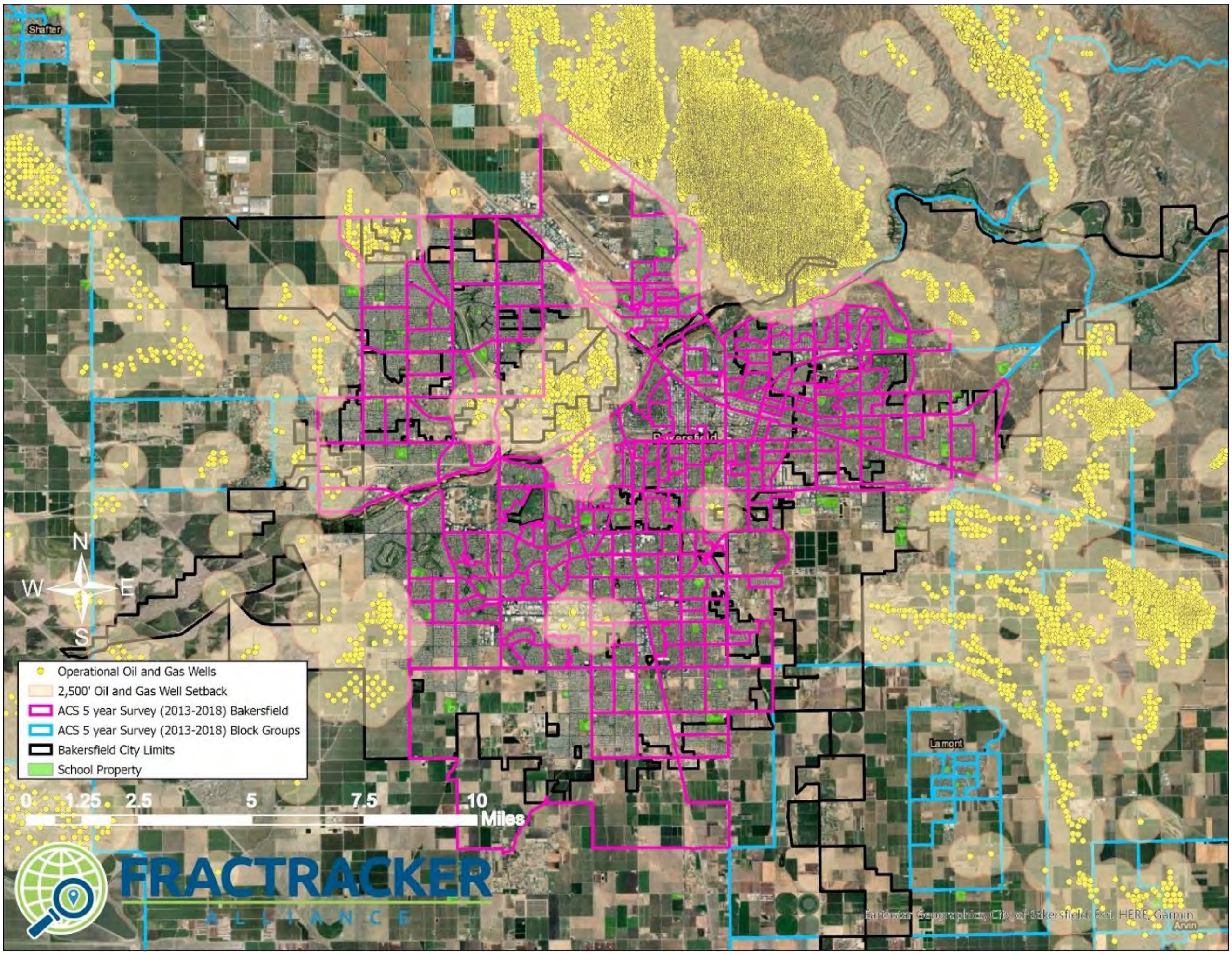


Figure 4. Map of the city of Bakersfield in Kern County, California located between several major oil fields including the Kern Front oil field. The map shows the 2,500' setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Southern California

Ventura

The City of Ventura and the proximity of the Ventura oil field is a similar situation to cities in Kern. The urban center of Ventura is bisected by the Ventura oil field's nearly 1,200 operational wells. While over 70% of the city's population is Latinx, the very sparsely populated census areas also containing portions of the oil field are 34% Latinx.

In the map below in Figure 5, take note of the population distribution within the portion of the city closest to the oil field versus the census areas to the east. While a statewide or less granular analysis would assume an evenly distributed population density, in this localized analysis, it is clear that the most vulnerable Frontline Communities are the urban centers closest to the oil fields. Even though the census blocks to the east contain oil and gas wells, the populations are less at risk because the population centers are located farther from the oil field.

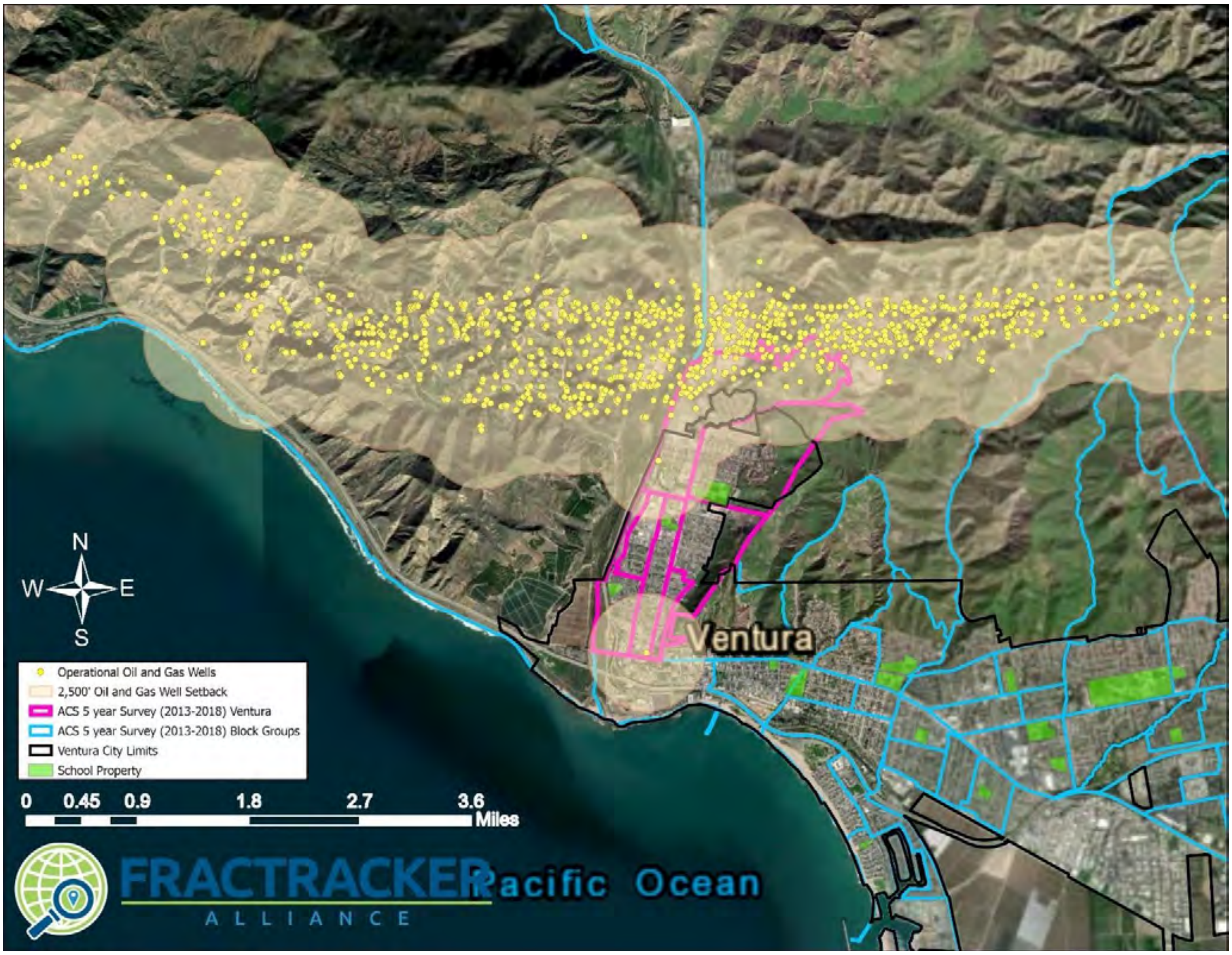


Figure 5. Ventura Oil Field in Ventura, California census areas within the 2,500' setback area. The map shows the 2,500' setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Los Angeles

In Los Angeles County, Inglewood, Wilmington, Long Beach, and Los Angeles City are some of the largest oil and gas fields. There are many areas in Los Angeles where a single low-producing well is located in an upper middle class suburb, on a golf course, or next to the Beverly Hills High School.

While all well sites present sources of exposure to volatile organic compounds (VOCs) and other air toxics, these four oil fields have incredibly high densities of oil and gas wells in urban neighborhoods. The demographics of the Frontline Communities located within 2,500' of these major fields are presented below in Table 4. These areas are additionally lower income communities; for example, over 50% of annual household incomes in the census areas surrounding the Los Angeles City oil field are below $40,000, while the Los Angeles County median annual income is over $62,000.

Table 4. Demographics for Frontline Communities living within 2,500' of Los Angeles's major oil and gas fields along with counts of operational wells in the fields are shown in the table. The demographic "Latinx" is the count of "Hispanic or Latino Origin" population, and "non-white" was calculated by subtracting "white only" from "total population."

Oil Field	Well Count	Non-white (%)	Latinx (%)
Inglewood	914	62%	11%

Wilmington	2,995	56%	63%
Long Beach	687	50%	30%
Los Angeles City	872	69%	59%
Ventura	1,193	10%	72%

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Inglewood

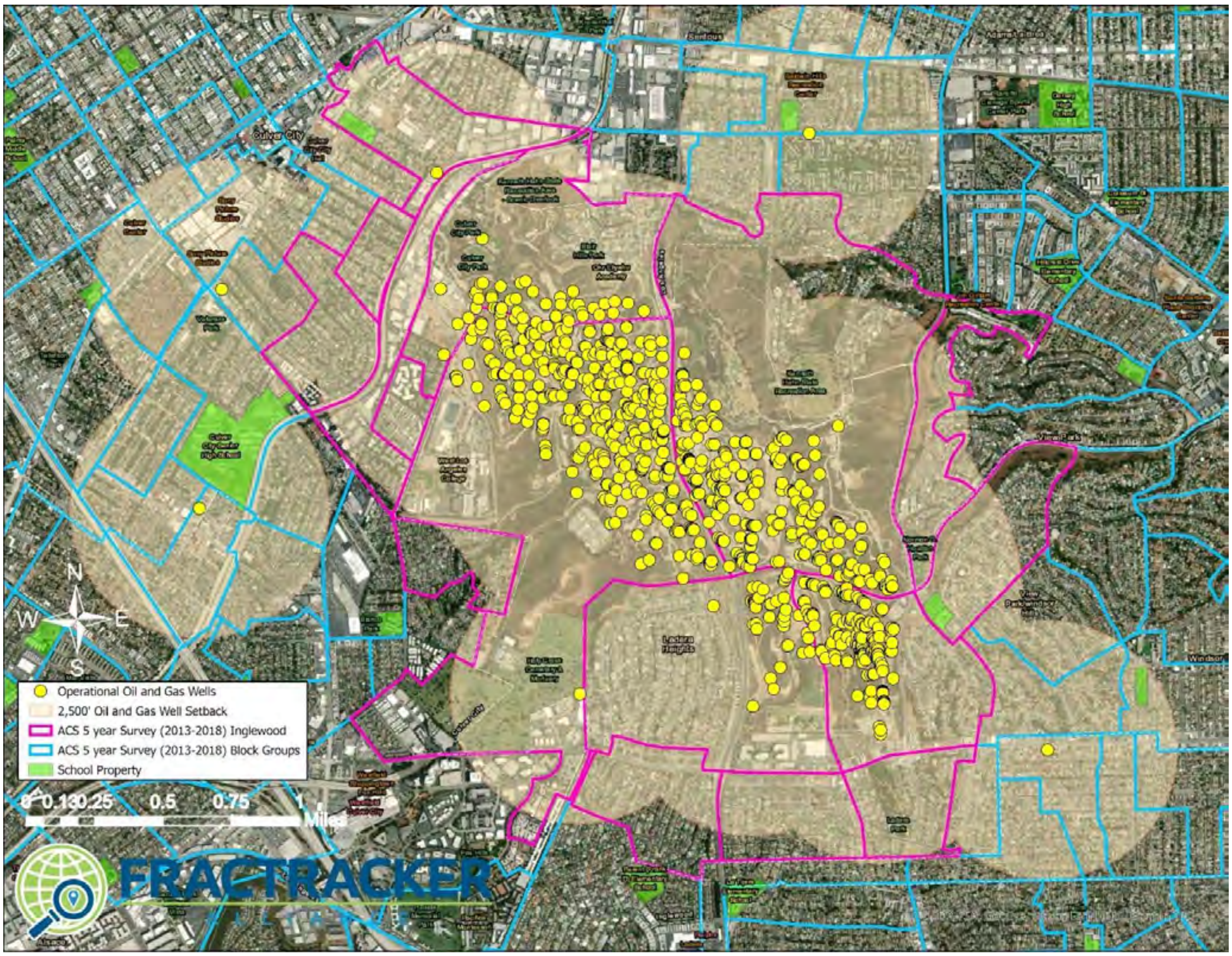

Figure 6. Inglewood Oil Field Frontline Community, Inglewood, California census areas within a 2,500’ setback area. The map shows the 2,500’ setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Wilmington

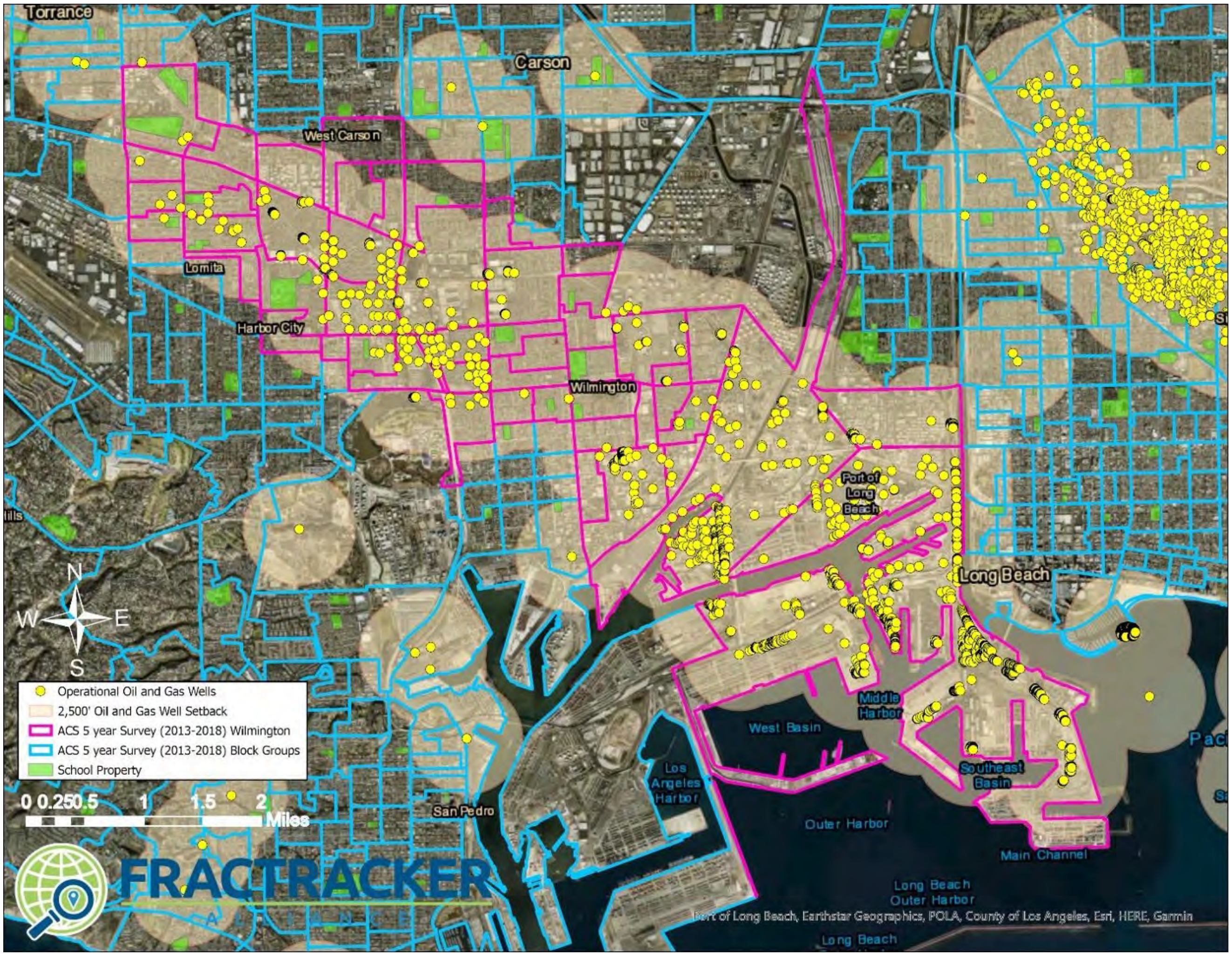

Figure 7. Wilmington Oil Field Frontline Community, Wilmington, California census areas within a 2,500’ setback area. The map shows the 2,500’ setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Long Beach

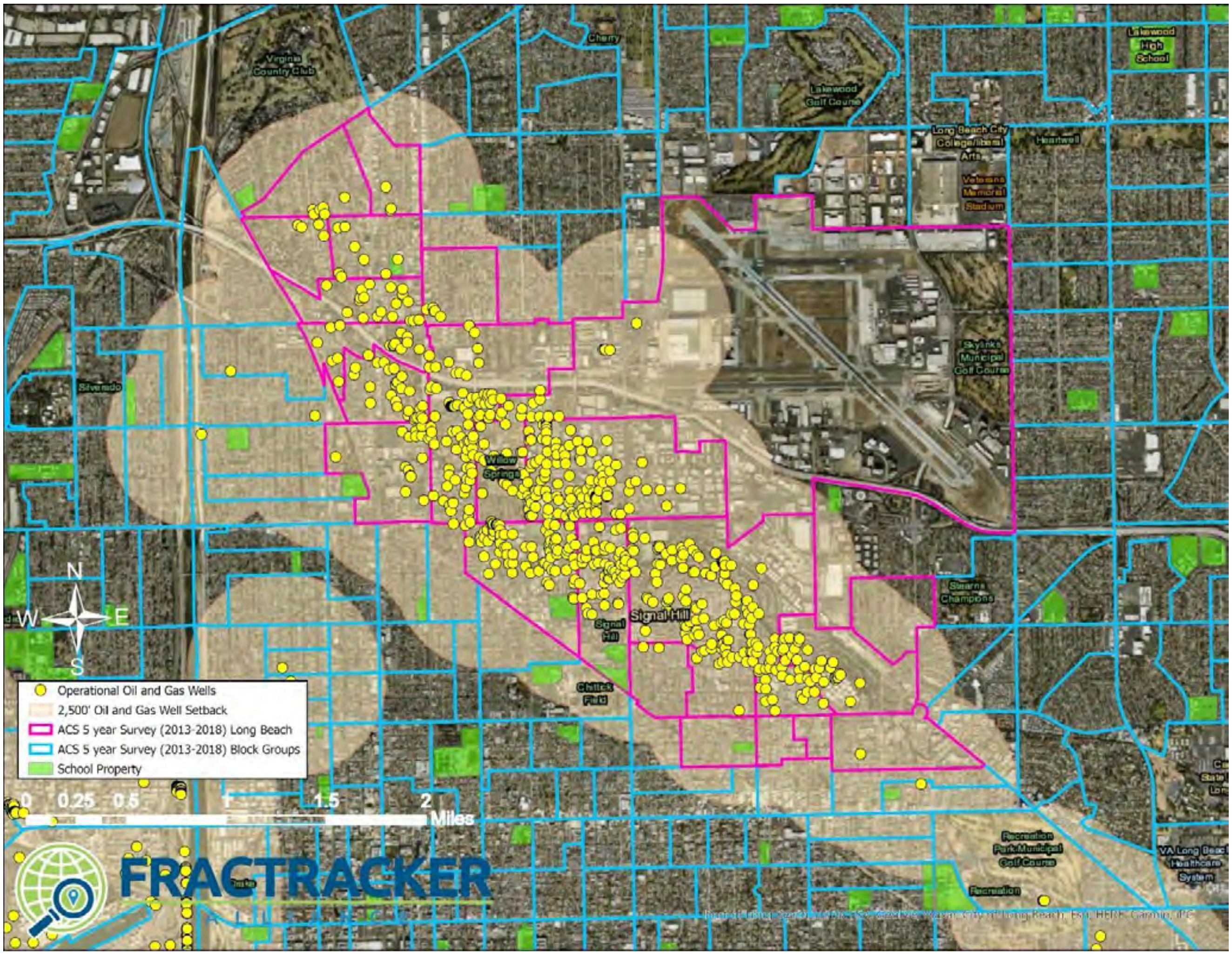

Figure 8. Long Beach Oil Field Frontline Community, Long Beach, California census areas within a 2,500' setback area. The map shows the 2,500' setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Los Angeles City

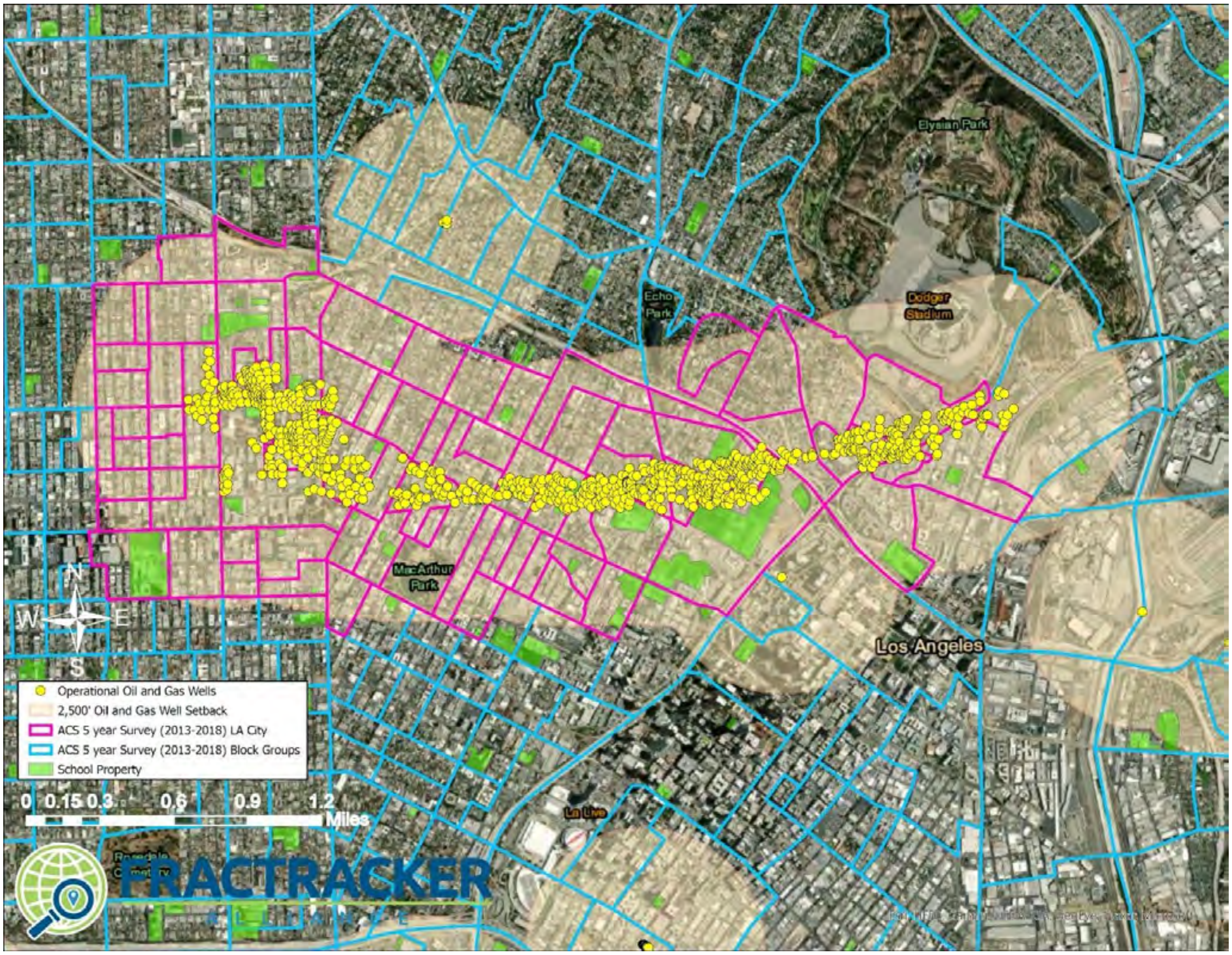

Figure 9. Los Angeles City Oil Field Frontline Community census areas within a 2,500' setback area. The map shows the 2,500' setback distance in tan, as well as the census block groups in both pink and blue. Pink block groups show the urban case populations used to generate the demographic summaries.

Production

The creation of public health policies such as 2,500' setbacks to help protect Frontline Communities is controversial in California as many state legislators are still beholden to the oil and gas industry. The industry itself pushes back strongly against any proposal that could affect their bottom line, no matter how insignificant the financial impact may be. When AB345 was proposed, the industry's lobbying organization Western States Petroleum Association claimed that institution of 2500' setbacks would immediately shut down at least 30% of California's total oil production. This number is an outright fabrication.

As shown in Table 1 above, a 2,500' setback would impact the less than 9,000 active and new wells; 42% in Kern County and 29% in Los Angeles County. Ventura and Orange Counties are a distant 3rd and 4th, respectively. These counts are further broken down by field in Table 5 below. Statewide these wells accounted for just 12.8% of California's current oil production by volume (as reported in barrels of oil/condensate by CalGEM), which is much smaller than the wholly unsubstantiated 30% decline claimed by industry.

Table 5. Counts of wells by well status for operational (active, idle, and new) oil and gas wells located within a 2,500' setback. Fields include the count of wells within the 2,500' setback and the amount of oil produced from those wells within the setback. The percentage of total oil from that field is also included.

Oil Field	County	Well Count	Well Ct % of Total	2019 Oil Prod (BBLS)	Oil Prod % of Total
Wilmington	Los Angeles	2,514	83%	2,292,669	22%
Kern River	Kern	1,338	9%	2,121,071	12%
Inglewood	Los Angeles	891	97%	1,806,354	96%
Midway-Sunset	Kern	1,892	10%	1,614,081	8%
Ventura	Ventura	287	24%	1,202,764	31%
Long Beach	Los Angeles	687	100%	1,036,506	100%
Brea-Olinda	Los Angeles	695	97%	967,223	95%
Huntington Beach	Orange	528	83%	753,494	42%
Placerita	Los Angeles	448	100%	508,182	100%
Santa Fe Springs	Los Angeles	304	99%	421,719	72%
Cat Canyon	Santa Barbara	115	10%	418,697	36%
Beverly Hills	Los Angeles	156	100%	351,877	100%
McKittrick	Kern	334	18%	346,738	10%
Montebello	Los Angeles	227	98%	318,657	97%
Fruitvale	Kern	286	80%	316,184	75%
San Ardo	Monterey	180	13%	313,339	4%
Torrance	Los Angeles	219	100%	307,413	100%
Seal Beach	Los Angeles	175	88%	282,790	74%

Shafter, North	Kern	70	78%	267,256	66%
Edison	Kern	520	41%	261,098	39%
Brentwood	Contra Costa	4	100%	230,868	100%
Oxnard	Ventura	124	82%	214,884	100%
Sansinena	Los Angeles	162	100%	207,474	100%
Poso Creek	Kern	320	16%	193,533	4%
Rosecrans	Los Angeles	94	100%	174,720	100%
Rio Bravo	Kern	80	74%	166,444	82%
Richfield	Orange	231	100%	165,426	100%
Coyote, East	Orange	81	100%	163,639	100%
San Vicente	Los Angeles	48	100%	162,940	100%

In the case that setback regulations are crafted both to prohibit new drilling and to phase out existing operations within the setback distance, the industry would have the opportunity to respond with measures that preserve the majority of production volumes, particularly in the Central Valley. For example, in Kern County, the overwhelming majority of new wells drilled in 2020 are directional or horizontal; these drilling technologies would allow operators to access the same below ground resources from surface locations that are further away from and safer for communities. Further, for existing wells within the 2,500’ setback, current proposals would institute a phase out period. Existing wells could be allowed to continue to operate under the terms of their current permits but not allowed to expand or rework their operations to increase or extend production; alternatively (or in addition), well operators could continue for a prescribed timeframe formulated to allow them to recoup their investment (called “amortization”).

Los Angeles

It is clear that the oil fields of Los Angeles would be the most impacted if setbacks phased out the wells responsible for the highest risk to Frontline Communities. The majority of Los Angeles’s urban oil fields are located entirely within 2,500’ of homes, schools, healthcare facilities and daycares.

As shown above in Table 5, wells within the setback produce 96% of the oil in the Inglewood fields, 84% in the Long Beach field, and 100% of the oil in several other smaller fields. With the phase out of these wells, oil extraction would cease in these fields. Most of these fields produce very low volumes of oil and already have high counts of idle wells, 28% idle in Wilmington, 25% in Inglewood, and 56% in Long Beach for example. The sole outlier of this trend is the Wilmington field. The majority of production in the Wilmington field comes from wells located in the Long Beach harbor, enough of them located outside of the 2,500’ setback such that while 83% of the Wilmington field wells are within the 2,500’ setback, these wells account for only 22% of the field’s overall production.

Kern County

The situation in Kern County is quite the opposite of Los Angeles, where the majority of operational wells are located within 2,500’ of homes, residences, and other sensitive receptors like healthcare facilities. In Kern, the overwhelming majority of wells are located beyond 2,500’ and even 1 mile from sensitive receptors. While the Midway-Sunset and Kern River fields have the most wells within the 2,500’ setback area, those wells make up a small percentage of the total operational wells in the fields. As can be seen in the map in Figure 1, wells within the 2,500’ setback zone in the large Kern oil fields are entirely located on the borders of the fields. Overall, a 2,500’ setback in Kern County would only affect 7.1% of active/new wells, accounting for 5.97% of the county’s production.

The oil and gas industry and operators in states including Texas, Colorado, North Dakota, Pennsylvania, Ohio, West Virginia, New Mexico, and Oklahoma are very vocal of their ability to avoid surface disturbance and target oil and gas pools located under sensitive receptors (homes, schools, healthcare facilities, endangered species habitat etc.) using directional drilling. According to the industry, directional drilling has been used for nearly a century to extract resources from areas where surface disruption would impact sensitive communities and habitats.

The same is true for California, especially in Kern County and especially recently. An October 2020 draft environmental impact report by the Kern County Planning and Natural Resource Department disclosed that in a dataset of 9,803 wells drilled from 2000 to 2020 by the California Resources Corporation, the majority of wells were drilled directionally (46%) or horizontally (10%), as opposed to vertically. More recent wells in the County have utilized directional and horizontal drilling even more heavily: a 2020 dataset of wells drilled county-wide indicates that 76% were drilled directionally and an additional 7% were drilled horizontally; only 17% were drilled vertically. These statistics indicate that, even if all wells neighboring Frontline Communities in Kern County were to be phased out (itself a small percentage of the total number of wells in the county), there would only be a small impact on Kern County oil production owing to the prevalence of non-vertical techniques that allow operators the flexibility to access reserves from different surface locations. As noted previously, if all oil production from within the 2,500’ setback zone were to be immediately eliminated statewide, it would mean a maximum decrease of just 12.8% of California’s current annual oil production. But the availability of directional and horizontal drilling in Kern County, where the lion’s share of all drilling statewide occurs, means it is more likely that the decrease in production will be significantly less than 12.8% and likely much less than 10%.

Existing Well Phase Out

Any assertion that a 2,500’ setback would immediately affect oil production is baseless because current setback proposals would institute a phase out period for existing wells. For example, existing permitted wells could be allowed to continue to operate under the terms of their current permits but not allowed to expand or rework their operations to increase or extend production. Alternatively, under a policy approach known as amortization, well operators could continue for a prescribed timeframe formulated to allow them to recoup their investment.

If wells within the setback distance are phased out pursuant to a “no rework” policy, operators would be afforded some time to maximize production in order to ensure that operators receive a sufficient return on their investment under the terms of their existing permits before they shut down. Under such an approach, older wells with increasing risks of fugitive emissions through leaks at the surface and well casing failures could be sequentially phased out by placing a ban on rework permits not required for maintenance or safety. CalGEM permitted well reworks, including sidetracks and deeper drills, increase production and the lifespan of wells. The catalog of rework permits can be found on the CalGEM website.

Based on CalGEM’s production data from 2018 and 2019, a phase out effectuated by disallowing well reworks would result in an annual reduction of less than 1% of total oil production. Of the 52,997 wells reporting oil/condensate production volumes in 2018, 338 received a rework permit in the same year. In 2019, of the 48,860 wells reporting oil production volumes, 285 received rework permits. By volume, the wells that received rework permits accounted for 0.87% of oil production in 2018 and just 0.04% in 2019.

Conclusion

The oil and gas industry in California has consistently pushed back against Frontline Communities who demand public health protections against emissions from oil and gas operations. This occurs even when there will be little to no impact reducing production. It is an industry policy to refuse any concessions and oppose all measures, even to protect public health, by leveraging the industry’s wealth at every level of the political hierarchy.

Fatefully, 2020 has resulted in multiple wins for public health in California. While the failure of AB345 made it clear that the California state legislature is still beholden to the fossil fuel industry, the momentum has continued. Community grassroots groups in Ventura County successfully passed a 1,500’ setback ordinance for occupied dwellings and 2,500’ setbacks for sensitive receptor sites including healthcare facilities and schools. Just south of Ventura, the County of Los Angeles is also in the midst of a rule-making process that is considering multiple setbacks, including 1,000’ to 2,500’ distances. And a committee of the Los Angeles City Council just voted to develop a proposal that would phase out oil drilling across the city as a non-conforming use.

While Ventura and Los Angeles are making progress, Kern County is creating a new process to streamline oil and gas well permitting and has even proposed to decrease the existing zone-specific 300’ setbacks from homes to 210’.

Kern County Frontline Communities and the rest of California also deserve the same consideration as residents of Ventura and Los Angeles Counties. The research is clear that a setback of at least one mile in addition to more site specific public health interventions are necessary to reduce the negative health impacts resulting from these industrial operations within and neighboring Frontline Communities.

By Kyle Ferrar, Western Program Coordinator, FracTracker Alliance

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Gas Companies Are Abandoning Their Wells, Leaving Them to Leak Methane Forever

Just one orphaned site in California could have emitted more than 30 tons of methane. There are millions more like it

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By **Mya Frazier**

September 17, 2020, 4:00 AM CDT *Updated on September 17, 2020, 3:05 PM CDT*

The story of gas well No. 095-20708 begins on Nov. 10, 1984, when a drill bit broke the Earth's surface 4 miles north of Rio Vista, Calif. Wells don't have birthdays, so this was its "spud date."

The drill chewed through the dirt at a rate of 80½ feet per hour, reaching 846 feet below ground that first day. By Thanksgiving it had gotten a mile down, finally stopping 49 days later, having laid 2.2 miles of steel pipe and cement on its way to the "pay zone," an underground field containing millions of dollars' worth of natural gas.

It was ready to start pumping two months later, in early January. While 1985 started out as a good year for gas, by its close, more than half the nation's oil and gas wells had shut down. How much money the Amerada Hess Corp., which bankrolled the dig, managed to pump out of gas well No. 095-20708 before that bust isn't known. By 1990 the company, now called simply Hess Corp., gave up and sold it. Over the next decade or so, four more companies would seek the riches promised at the bottom of the well, seemingly with little success. In 2001 a state inspector visited the site. "Looks like it's dying," he wr

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Gas well No. 095-20708 under “tent chamber” for testing.
Photographer: Eric Lebel

Well No. 095-20708 is also known as A.H.C. Church No. 11, referring both to Hess and to Bernard Church, who like so many in California’s Sacramento River Delta sold his farmland but retained the mineral rights in the hope that they’d make his fami
Church well is a relic, but it’s not rare. It’s one of more than 3.2 million desert

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In the past five years, 207 oil and gas businesses have failed. As natural gas prices crater, the fiscal burden on states forced to plug wells could skyrocket; according to Rystad Energy AS, an industry analytics company, 190 more companies could file for bankruptcy by the end of 2022. Many oil and gas companies are idling their wells by capping them in the hope prices will rise again. But capping lasts only about two decades, and it does nothing to prevent tens of thousands of low-producing wells from becoming orphaned, meaning "there is no associated person or company with any financial connection to and responsibility for the well," according to California's Geologic Energy Management Division.

"It's cheaper to idle them than to clean them up," says Joshua Macey, an assistant professor of law at the University of Chicago, who's spent years studying fossil fuel bankruptcies. "Once prices increase, they could be profitable to operate again. It gives them a strong reason to not do cleanup now. It's not orphaned yet, although for all intents and purposes it is."

The life cycle of the Church well exemplifies this systemic indifference. Hess's liability ended when it sold more than 30 years ago; the last company to acquire the lease, Pacific Petroleum Technology, which took over in 2003, managed to evade financial responsibility entirely as the well's cement and steel piping began to corrode. Copy Link
from state regulators demanding that the company declare its plans for the well went

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under parking lots and shopping malls, even near day-care centers and schools in populous cities such as Los Angeles, where at least 1,000 deserted wells lie unplugged. In Colorado an entire neighborhood was built on top of a former oil and gas field that had been left off of construction maps. In 2017 two people died in a fiery explosion while replacing a basement water heater.

These kinds of headline-grabbing episodes are anomalies, but all this leaking methane also has dire environmental consequences, and the situation is likely only to get worse as more companies fail. "The oil and gas industry will not go out with a bang," Macey adds, "but with a whimper." As it does, the wells it orphans will become wards of the state.

Days before the 33rd anniversary of Church's spud date, in November 2017, Eric Lebel, a researcher with the School of Earth, Energy & Environmental Sciences at Stanford, arrived at the wellhead. The rusted 10-foot structure—a "Christmas tree," as it's called in the industry—loomed over him.

While Lebel knew the well's depth, it was still hard for him to envision its scale. "If you don't see it, you don't think about it," he says later. "What's underground is impossible to imagine." The Earth's interior has been unfathomably scarred by hydrocarbon infrastructure, he says. For almost two centuries, since the drilling of the first

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Lebel measures methane emissions from an abandoned well near Paicines, Calif.
Photographer: Rob Jackson, Stanford University

Now imagine each of those pins in the global pincushion is a straw inside a straw. In Church's case, the outer straw is 7.625 inches in diameter and made of steel, encased in cement; inside is a 2.375-inch-wide steel tube. The deeper the well, the more t

pressure rise. At Church's deepest point, 10,968 feet, the temperature likely ex

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thing to go get empirical data."

Kang went to Pennsylvania, where boom and bust cycles over the years have left a half-million gas wells deserted. Of the 19 she measured, three turned out to be high emitters, meaning they released three times more methane into the atmosphere than other wells in the sample. "There were no measurements of emissions coming out of these wells," she says. "People knew these wells existed, they just thought what was coming out was negligible or zero." By scaling up her findings, Kang was able to estimate that in 2011, deserted wells were responsible for somewhere from 4% to 7% of all man-made methane emissions from Pennsylvania.

Those findings inspired Lebel and other researchers in the U.S. and worldwide to start taking direct methane measurements. The industry responded by ignoring them and fought fiercely against the Obama administration's efforts to start regulating methane emissions. (A 2016 rule requiring operators to measure methane releases at active wells and invest in technology to prevent leaks was summarily overturned by the Trump administration at the beginning of August.)

Meanwhile, scientists trudged on. So far researchers have measured emissions at almost 1,000 of the 3.2 million deserted wells in the U.S. In 2016, Kang published another study of 88 abandoned well sites in Pennsylvania, 90% of which leaked methane.

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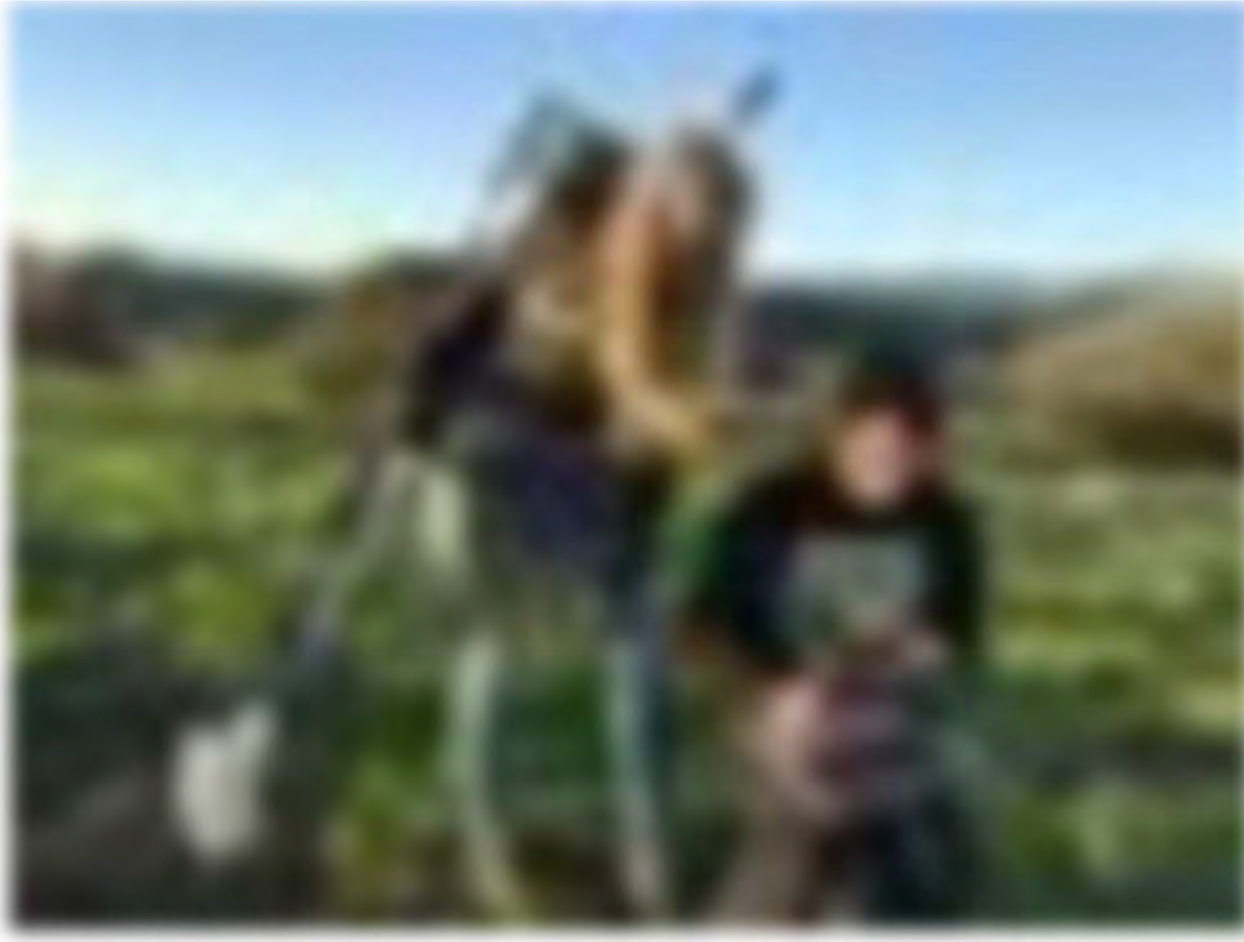

Lebel and Lisa Vielstädte use a magnetometer to locate abandoned oil and gas wells buried near La Honda, Calif.
Photographer: Rob Jackson, Stanford University

Internationally, researchers tracked increasingly bad news. German scientists discovered methane bubbles in the seabed around orphaned wells in the North Sea. Taking direct measurements of 43 wells, they found significant leaks in 28. In Alberta, resea

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At 3:41 p.m., using an instrument that resembles a desktop computer with an abundance of ports, Lebel took his first methane measurement. “We knew right away it was a major leaker,” he recalls. It exceeded the instrument’s threshold of 50 parts per million almost immediately. Lebel collected air samples in tiny glass vials to take back to his lab. The analysis was damning: Two hundred and fifty grams of methane were flowing out of the well each hour. A rough calculation shows that over a decade and a half the Church well had likely emitted somewhere around 32.7 metric tons of methane, enough to melt a sizable iceberg.

Despite the flurry of recent research, the full scale of the emissions problem remains unknown. “We really don’t have a handle on it yet,” says Anthony Ingraffea, a professor of civil and environmental engineering at Cornell who’s studied methane leaks from active oil and gas wells for decades. “We’ve poked millions of holes thousands of feet into Mother Earth to get her goods, and now we are expecting her to forgive us?”

There’s no easy way to bring up the thousands of feet of steel and cement required to carry gas out of a well as deep as A.H.C. Church 11. That means the only way to keep the well from leaking is to fill it up. Plugging a well costs $20,000 to $145,000, according to estimates by the U.S. Government Accountability Office. For modern shale wells, the cost can run as high as $300,000.

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The tiny packer, just 2.5 inches wide, stayed stuck for weeks. As the crew tried to get it out, tubing inside the well broke—"structurally compromised due to corrosion," they told California's Department of Conservation in the work log they submitted. They were forced to go "fishing," using specialized tools to retrieve the tubing, piece by broken piece. But the packer was still in there. Eventually they used even more specialized tools to grind it away.

It wasn't until July 26, almost a month after workers arrived at the Church site, that they were able to start "running mud," the industry term for pumping cement into the outer straw. This straw had been purposely perforated to allow oil and gas to flow from the pay zone into the well. The plugging cement is supposed to accumulate upwards as more gets pumped in. But if it leaks off into that porous pay zone, no matter how much mud the team runs, it simply disappears. Unless the cement and other sealants reached every nook and cranny, the site might continue to leak.

Thankfully, Church filled easily, requiring 36,500 pounds of cement. The unforeseen difficulties added $171,388 to Paul Graham's original estimate, raising the total bill to $294,943, more than double the crew's $123,555 bid. (Neither the cleanup company nor the state representatives who oversaw the work responded to interview requests.) Ingraffea examined the myriad work orders from the job and called it a "well from hell."

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By late August, almost two months after they arrived at the Church site, the cr

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permits.

“We make the same mistake over and over again,” says Rob Jackson, a professor of Earth system science at Stanford who oversees Lebel’s work. “Companies go bankrupt, and taxpayers pay the bills.”

Congressional efforts to create a well-plugging program for cleanup are stalled. Meanwhile, oil and gas companies have made trillions of dollars in profits over the past century and a half while enjoying relative impunity. On federal lands, where oil and gas companies actively drill, bond levels haven’t been adjusted for inflation since 1951, when they were set at $10,000 for a single well and $150,000 for however many wells a single operator controls nationwide. In California a company drilling 10,000 feet or more needs only $40,000.

Even spending all the billions of dollars required to plug the world’s millions of deserted wells won’t stave off environmental catastrophe. The vast heat and pressure of the Earth’s subsurface—the same forces that crushed dinosaur bones into hydrocarbons in the first place—mean that no plugging job lasts forever. Scientists and engineers debate how long cement can survive in the harsh environment of the Earth’s interior. Estimates typically fall from 50 to 100 years, a long enough time horizon that even some of today’s oil and gas companies may no longer exist, but short enough to be uncomfortably within the

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"There's so much we don't know."

What we do know is scary enough. "The cement will deteriorate," says Dominic DiGiulio, a senior research scientist for PSE Healthy Energy, an Oakland, Calif.-based public policy institute, who worked for the Environmental Protection Agency for more than three decades in subsurface hydrology. "It's not going to last forever, or even for very long." A.H.C. Church lies in the Solano Subbasin, part of the Sacramento Valley Groundwater Basin. Almost 30% of the region's water comes from subsurface sources, according to a 2017 report from the Northern California Water Association. "Given sustained droughts, groundwater resources are going to be very important in the coming decades," DiGiulio says. "California is going to need these resources."

Among the hundreds of pages of records chronicling the well's spud, activity, and plugging, the one consistent name was Bernard Church. One afternoon this summer, I called the phone number listed on the most recent document, from a 2004 inspection, and reached his wife, Beverly Church. She now lives in Walnut Creek, Calif., about 40 miles southwest of the well site, and she told me her husband had died nine years earlier.

He and their family never became rich. Holders of mineral rights can lease them back to oil and gas companies and receive royalties on what their wells produce. But because so little had been pumped from Church, none of the 20 or so family members who eventually held a stake wound up with much. "We didn't make any money off

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Beverly says

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(Updates third paragraph to clarify what happened in January 1985.)

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COMMENTARY

Drilling Down on Oil: The Case of California's Complex Midway Sunset Field

Given the state's future oil prospects along with large volumes currently being produced, refined, and sold, it is incumbent that elected officials and the public better understand California's oils.

By **Deborah Gordon** and **Samuel Wojcicki**

Published on March 15, 2017

Overview

California has vast, complicated, and extremely varied carbon-packed oils about which little is known. The state's Monterey oil formation is one of the nation's largest. Exact recoverable reserve amounts vary as technology advances and oil prices fluctuate, but **billions of barrels** are buried there. A century ago, long before climate change was a concern, California recognized the striking differences between its fields and launched **historic efforts** to understand its heaviest, most difficult to process oil by charting Midway Sunset, its largest and most productive oilfield. Yet even as the state has moved aggressively and decisively to become a climate leader, these kinds of efforts to better understand its oils have lapsed. Today, Midway Sunset is still California's most productive field, with oils that have grown heavier and more complex as it has aged, while air quality in the surrounding region constitutes **the worst in the nation**. What resources actually comprise this **super-giant** oil field that has produced billions of barrels is still largely unknown and must be ascertained and publicly disclosed.

To that end, a new open-source model—the **Oil Climate Index** (OCI)—estimates that Midway Sunset is one of the world's most **climate intensive oils** tested to date. Barrel for barrel, Midway Sunset, which produces 70,000 barrels per day, has greenhouse gas (GHG) emissions that rival Canadian oil sands.

Given the state's future oil prospects along with large volumes currently being produced, refined, and sold, it is incumbent that elected officials and the public better understand California's oils. Information is key, including routine collection of standardized oil assays and steam required in production. This would not only protect public health and safety, the local environment, and global climate—it would also establish a global precedent for assessing the GHG emissions associated with the increasingly diversified array of oil resources worldwide.

Targeting Midway Sunset

There is no better place to start this quest of drilling down deeper to evaluate oil and inform decision making than Midway Sunset oil field. One of the state's oldest, is located in Kern County at the southern end of the San Joaquin Valley about 40 miles southwest of Bakersfield. Asphalt deposits were first sighted in 1858, the field was tapped in 1894, and within decades Midway Sunset turned into a gusher that has since produced over 3 billion barrels from its tens of thousands of wells. This mature field in the midst of depletion continues to experience significant reserve growth due to enhanced recovery methods that flood and cycle steam as well as reinject water to keep oil flowing despite the growing list of production challenges.

As early as 1919, the federal government surveyed Midway Sunset's striking difference compared to other California oils, which themselves are considered unusual in many important respects from oil produced elsewhere in the United States. Much of the oil found in California is extremely heavy, with characteristics akin to oil sands. Some 5 trillion barrels of heavy oil is estimated to be in place worldwide. While these low-quality reserves reside in every global hemisphere—from California and Canada to Venezuela and Russia—it is estimated that California contains nearly one-half of the country's heavy oil that requires complex technology to produce and refine.

Midway Sunset oil is uneven, unstable, and waterlogged. Geologically, its oil-bearing beds range from relatively young to very old. Ten times more water is pumped out of Midway Sunset than oil. Its quality and weight fluctuates markedly—from as little as 8° API gravity near the outcrop up to 32° at greater depths—with consistencies ranging from the thickest peanut butter to gooey molasses to runny maple syrup.

Assessing Midway Sunset GHGs Through the Oil Supply Chain

Using the Oil Climate Index (OCI), a collection of three models discussed below, the climate impacts of oils can be compared—barrel for barrel—from their upstream production, midstream refining, and downstream end use. What is noteworthy is how wide-ranging different oil's GHGs can be. In a test of 75 global oils—25 percent of current production—there is a 60 to 90 percent difference in climate impacts between the least carbon intensive and the most. Midway Sunset is included in the OCI analysis. As stated above, the OCI estimates that Midway Sunset, at current production levels, is one of the highest emitters modeled in the OCI, nearly as climate intensive barrel for barrel as oil sands. But this highly complex field may contain oils that, depending on their particular characteristics, are even higher than the OCI initially estimated.

When it comes to estimated upstream production GHGs, Midway Sunset has been provisionally modeled along with 153 other California oils in the Oil Production Greenhouse Gas Estimator Model. Extracting a barrel of Midway Sunset is estimated to release 180 kilograms of carbon dioxide equivalent emissions (kg CO_2 eq./bbl crude), making this field one of the highest-emitting oils produced in the state. Over the past fifty years, enhanced recovery techniques have been employed as Midway Sunset oil has aged, leading to a four-fold increase in upstream production emissions. If these trends continue and steam injection rates rise, upstream emissions could possibly increase further to over 200 kg CO_2 eq./bbl crude. And beyond elevated climate risks, operating in this densely developed, highly fractured formation is a dangerous enterprise.

Continuing to collect data on steam usage would facilitate routine updating of this field's production emissions profile, enhancing policymaker oversight of Midway Sunset's 40 operators, including Aera, Chevron, and Linn (an investor partnership).

Midway Sunset also presents climate challenges during refining that are assessed with the Petroleum Refinery Life Cycle Inventory Model, PRELIM. This analysis is limited by the surprising lack of information about this field's varied nature. Despite its known complexity, there is only a single, questionable publicly available oil assay for Midway Sunset. Even under a best-case scenario, refining Midway Sunset is estimated to emit 81 kg CO_2 eq./bbl crude, ranking it as one of the highest GHG emitters compared to the 75 global oils modeled in the OCI. The use of proxy assays to better represent the varying nature of this heavy oil suggest that refining emissions may be at least 10 percent higher.

The lack of clear characterization of Midway Sunset due to missing assays creates critical uncertainties in modeling downstream end use emissions. The OCI employs the Oil Production Emissions Module, OPEM, to obtain the volumes of petroleum products reported out in PRELIM and calculate their GHG emissions in end use. The only oil assay that is publicly available dates back to 1978 and is published by Knovel. This assay characterizes Midway Sunset as a medium-weight oil (22.6° API gravity) with commensurate GHG emissions estimated at 464 kg CO_2 eq./bbl crude. Yet there is sufficient evidence to the contrary; Midway Sunset is actually quite heavy. Chevron markets this benchmark crude at 13° API gravity and USGS records indicate gravities below 11° API, although no open-source assays are available for these different Midway Sunset oils.

Absent actual assay data, we can model Midway Sunset using proxy assays from other oils at 19°, 12°, 10°, and 8° API gravities and run them through complex coking refineries. End use emissions that are modeled through OPEM are as high as 500 kg CO_2 eq./bbl crude. Increased emissions are associated with increasing volumes (as much as one-fourth total product yield) of petroleum coke, or petcoke. Petcoke is a solid, residual fuel that is too dirty to use in California and is exported to India and other countries where its combustion may **adversely impact** the local environment.

Updated, verifiable oil assay data and steam-to-oil ratios (SOR) are lacking for California Midway Sunset. The three Midway Sunset scenarios labeled in this figure were modeled using different OCI input assumptions in order to estimate the significant range in this complex oil's greenhouse gas emissions. Certain scenarios estimated Midway Sunset total GHG emissions may be higher than some Canada Oil Sands.

- **Scenario A** – Publicly available Assay: Midway-Sunset supplied by Knovel, API: 22.6°, Steam to oil ratio (SOR): 5.79. While Scenario A uses an actual Midway Sunset assay, it is not thought to be entirely representative of this complex field.
- **Scenario B** – Public proxy Assay: Venezuela Tia Juana supplied by Stratiev, API: 12.1°, SOR: 5.79. While Scenario B uses a proxy assay, it is thought to be more representative of the 13° API gravity Midway Sunset that is posted monthly as a benchmark crude by the Oil & Gas Journal.
- **Scenario C** – Proxy Assay: Athabasca Bitumen Thermal supplied by Alberta Energy, API: 8.1°, SOR: 7.50. While Scenario C uses a proxy assay, it may provide a better approximation of the higher end of GHGs for lower quality Midway Sunset oil that is similar to Canadian oil sands.

Note: Emissions may not add up due to rounding; the sulfur content of different Midway Sunset crudes, like many other California oils, is not consistently reported. Proxy assay sulfur content may not be representative of Midway Sunset crudes. But this should not affect appreciably alter GHG estimates in the OCI.

Protecting Air Quality Too

The challenges posed by Midway Sunset extend beyond climate change. Production of heavy oils, including the oil sands found in Canada, **are known to produce secondary organic aerosols (SOAs)** that **make up fine particulate** pollution (PM 2.5). PM 2.5 is a dangerous air quality criteria pollutant that has been tied to increased risk for cancer, diabetes, and various lung and heart problems. A recent study found that production of Albertan oil sands is the leading source of air pollution in North America, emitting twice as much SOAs as car and truck exhaust.

While the pollution impacts from Midway Sunset oil production have not been as carefully examined, similarities between the composition of oil sands and Midway Sunset's complex oil raise local air quality concerns. Nearby Bakersfield is home to the highest rates of particulate pollution in the nation, according to a 2016 American Lung Association report.

Refining heavy oils like Midway Sunset use coking processes to reject the excess carbon and turn these oils into more gasoline and diesel. These deep conversion refineries have high particulate emissions that are directly released into the surrounding atmosphere. The California Air Resource Board has recently proposed emission reduction goals aimed in part to reduce pollution in nearby communities over health concerns.

Air quality problems trail Midway Sunset oil to petroleum product consumption, where fuel grade petcoke that is too dirty to burn in California is shipped to Asia and elsewhere. And pollution from exported residuals may return to California in prevailing winds and intercontinental transport.

Staying Informed in the Next Age of Oil

Once upon a time, oil gushed when poked, flowed easily with little prodding, and was readily distilled into gasoline with minimal treatment and reforming. Today, oil conditions have changed. Increasing effort is going into producing, transporting, refining oil, and consuming its growing array of petroleum byproducts. California is a testament to these difficulties. Regulatory oversight is an ongoing concern. And managing oil in a warming world will be an ongoing challenge along with protecting local environmental health and safety.

California has the opportunity to lead the world in the responsible management of its heavy oil resources. This path must be illuminated by the routine collection of standardized, open-source oil data. And there's no better place to start than with Midway Sunset.

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Oil sands operations as a large source of secondary organic aerosols

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Worldwide heavy oil and bitumen deposits amount to 9 trillion barrels of oil distributed in over 280 basins around the world[1], with Canada home to oil sands deposits of 1.7 trillion barrels[2]. The global development of this resource and the increase in oil production from oil sands has caused environmental concerns over the presence of toxic compounds in nearby ecosystems[3,4] and acid deposition[5,6]. The contribution of oil sands exploration to secondary organic aerosol formation, an important component of atmospheric particulate matter that affects air quality and climate[7], remains poorly understood. Here we use data from airborne measurements over the Canadian oil sands, laboratory experiments and a box-model study to provide a quantitative assessment of the magnitude of secondary organic aerosol production from oil sands emissions. We find that the evaporation and atmospheric oxidation of low-volatility organic vapours from the mined oil sands material is directly responsible for the majority of the observed secondary organic aerosol mass. The resultant production rates of 45–84 tonnes per day make the oil sands one of the largest sources of anthropogenic secondary organic aerosols in North America. Heavy oil and bitumen account for over ten per cent of global oil production today[8], and this figure continues to grow[9]. Our findings suggest that the production of the more viscous crude oils could be a large source of secondary organic aerosols in many production and refining regions worldwide, and that such production should be considered when assessing the environmental impacts of current and planned bitumen and heavy oil extraction projects globally.

In general, secondary organic aerosol (SOA) mass is formed from the oxidation of organic gases, producing new compounds of sufficiently low saturation concentration (C*) that can nucleate or condense onto pre-existing particles. SOA typically dominates total organic aerosol (OA) mass, and can account for >50% of particulate matter mass below 2.5 μm ($PM_{2.5}$) at many locations in the northern hemisphere[10]. SOA is partially derived from the oxidation of routinely measured volatile organic compounds (VOCs; $C^* > 10^6\,\mu g\,m^{-3}$). However, recent evidence[11,12] suggests that semi-volatility compounds (SVOCs; $C^* = 10^{-1}-10^3\,\mu g\,m^{-3}$) and intermediate-volatility compounds (IVOCs; $C^* = 10^3-10^6\,\mu g\,m^{-3}$) are also important aerosol precursors owing to their high aerosol yields[13]. While oil and gas production and processing, including oil sands (OS) production, are known sources of VOC emissions[14], their SVOC and IVOC emissions are unquantified. This is particularly relevant for the OS, since the mined material is a mixture of sand, water and clay coated in bitumen, the latter being an extremely viscous (and low-volatility) form of petroleum recovered through surface mining. During the Deepwater Horizon (DWH) oil spill, SVOCs and IVOCs were the predominant precursors of SOA formed downwind of the spill[15]. Heavy oils and bitumen are comprised of lower-volatility hydrocarbons than DWH crude[16], such that their extraction and processing might be expected to release a disproportionately large fraction of SVOCs and IVOCs into the atmosphere compared to lighter crude oil. On average, $5.04 \times 10^6\,m^3\,month^{-1}$ of bitumen was produced from OS surface mining operations in 2013 (ref. 17); should it be even slightly volatilized during production, there would be a strong potential for large amounts of SOA to be formed downwind of the region. This SOA formation potential from SVOC and IVOC emissions is demonstrated later.

Three aircraft measurement flights (F1, F2, F3) were conducted in Lagrangian patterns (Extended Data Fig. 1 and Supplementary Table 1), in which the same plume from OS operations was repeatedly sampled along tracks perpendicular to the plume axis (see Methods). Each flight intercepted two large, well-mixed plumes, revealing rapid SOA formation during transport, as illustrated in Extended Data Fig. 2 for F1 (similarly observed during F2 and F3). One plume was dominated by SO_2 and sulfate aerosols and the other by OA. While the sulfur plume can be traced back to OS facility stack emissions associated with desulfurization of raw bitumen, the origin of the large OA plume was less clear, and yet OA accounted for >80% of the aerosol mass (Extended Data Fig. 2). As the aircraft flew to different downwind distances from the OS (screens A, B, C and D), peak OA mass increased from ~10 to 14 μg m^{-3} (A to B) and remained constant at ~12 μg m^{-3} (C to D), despite ongoing dilution (indicated by large decreases in SO_4^{2-} and black carbon (BC) aerosol concentrations), plume broadening (39 to 72 km) and particle deposition. This indicates a considerable SOA formation rate within these plumes, overriding the effect of dilution. Using BC as a tracer to correct for these effects (as described in Supplementary Discussion), a sixfold relative increase in OA mass (as SOA) is observed over 4 h (Fig. 1).

Net SOA formation rates were derived on the basis of mass balance using the OA mass transfer rates (tonnes (t) h^{-1}) across the flight screens[18]. The SOA formation rate is the OA transfer rate difference between screens. A description of the SOA production rate calculation, extrapolation assumptions and associated uncertainties is given in Methods. Accordingly, during F1, 3.4 ± 0.9 t h^{-1} of SOA was formed over ~90 km (A to D; Fig. 2), 2.7 ± 1.0 t h^{-1} between the screens of F2, and 2.1 ± 0.9 t h^{-1} during F3 (Extended Data Fig. 3). Including the SOA formed between the source region (S) and A, the cumulative SOA formation rates were 4.7 ± 0.9, 5.3 ± 1.0 and 4.3 ± 0.9 t h^{-1} during F1, F2 and F3, respectively. Scaling by the time-integrated OH radical concentration over daylight hours, these formation rates translate to 45–84 t day^{-1} during the summer season. These remain underestimates since they do not include deposition or SOA formation beyond the last flight screens or at night. Correcting for depositional loss increases the rates to 55–101 t day^{-1}.

The rates of SOA formation observed here are very large; the relative rate of OA enhancement depicted in Fig. 1 is comparable to downwind of megacities such as Mexico City[19] and Paris[20], and is higher than that

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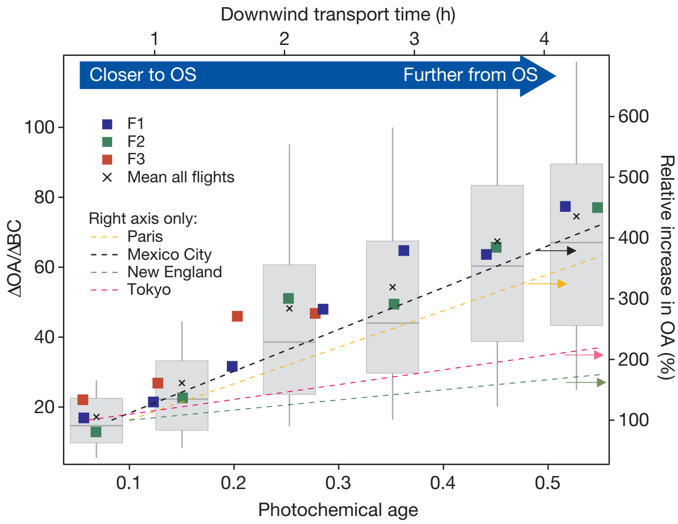
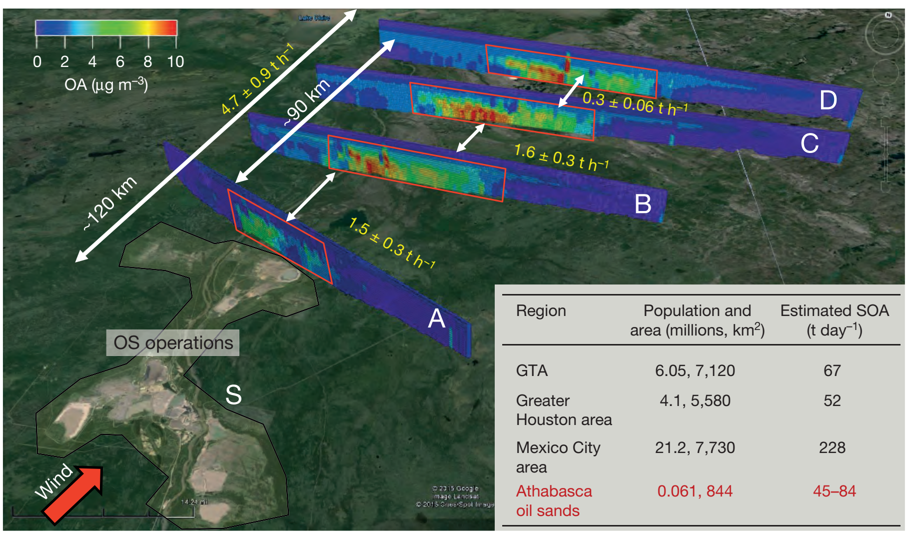


Figure 1 | Relative increase in OA downwind of the OS. The above-background (Δ)OA is normalized by BC (ΔOA/ΔBC; left axis) and shown as a function of photochemical age ($-\log(NO_x/NO_y)$; bottom axis) and air mass transport time (top axis). Increases in ΔOA/ΔBC indicate SOA formation. A sixfold relative increase in OA is observed (right axis), comparable to those reported downwind of large urban areas[19–22]. Data points represent the average of the point-by-point ΔOA/ΔBC binned by photo-chemical age. Grey boxes and whiskers represent 10th, 25th, 75th and 90th percentiles of the data from all three flights ($n = 2{,}573$).

observed in Tokyo[21] and New England[22], while the absolute rate (Fig. 2) is comparable to that estimated during the DWH oil spill (~3.3 t h^{-1}; ref. 15). However, a more compelling comparison to the absolute rate is with SOA formation rates downwind of major urban centres using available data (Fig. 2). For these urban centres, the SOA formed within one photochemical day was estimated using reported ΔOA/ΔCO ratios and daily CO emissions, assuming that CO is co-emitted with SOA precursors[23,24] (see Supplementary Discussion). The SOA formation rates downwind of the Greater Toronto Area (Canada's largest metropolis), Houston and the Mexico City Metropolitan area are estimated at 67, 52 and 228 t day^{-1} (not accounting for deposition), respectively. Despite the noted uncertainties described in Supplementary Discussion, this comparison illustrates that OS operations are one of the largest sources of anthropogenic SOA in North America.

The SOA in these OS plumes had characteristics of two types of oxygenated organic aerosols (OOA)[25] as represented by two factors derived from positive matrix factorization (PMF) analysis of aerosol mass spectrometry data. Factor 1 (Extended Data Fig. 4) was more oxygenated than factor 2 (Fig. 3a), indicating that it was more photo-chemically aged. The time series of the factors during F1 are shown in Fig. 3b. Factor 1 was regionally distributed, dominating outside the plumes (>80%) at 3–5 μg m^{-3}, and largely consisted of aged regional biogenic SOA, as its mass spectrum was highly similar to those reported over forests[26] and from monoterpene oxidation in smog chamber experiments (Extended Data Fig. 4)[27]. Factor 2 accounted for >90% of the SOA mass in the plume and was freshly formed from the oxidation of OS emissions. Its mass spectrum is almost identical to the spectra of OA derived from the OH oxidation of bitumen vapours in chamber experiments ($r^2 > 0.96$) (Fig. 3a and Extended Data Fig. 4), indicating that bitumen vapours are important precursors to the large SOA formation rates in OS plumes (see Supplementary Discussion).

The contribution of oxidized bitumen vapours to the observed SOA depends strongly on the initial volatility of the SOA precursors[11]. To assess their SOA formation potentials, the volatility distributions (VDs) of bitumen vapours evolved from OS ore were determined (see Supplementary Methods), where the VD represents the fractions of total vapour in different ranges of C*. At 20 °C, the majority of vapour evolved is in the C_{14}–C_{16} hydrocarbon range (IVOC; $C^* = 10^5$ μg m^{-3}), and shifts only slightly at 60 °C (Fig. 4a). While gaseous emissions exist that span the C_{12}–C_{18} range at ambient temperatures, heating of the material (70 °C) results in complete evaporative loss up to C_{15} (Extended Data Fig. 5), leaving primarily compounds from C_{16} to $>C_{30}$. This represents a volatilization of ≤15% of the total extractable hydrocarbon mass from the ore at 50 °C, increasing further at higher temperatures (Fig. 4b). In surface mining operations, ore material is obtained via open-pit mining followed by bitumen-sand separation using hot water (40–80 °C) and further refining at up to 500 °C. These derived bitumen vapour VDs clearly demonstrate the potential for atmospheric emissions of SOA precursors in a C* range associated with strong SOA formation[11,13]. On the basis of their volatility, such emissions are certain to occur during open-air mining and the various heated processing steps. Ambient ground-based measurements also show the existence of hydrocarbons



Region	Population and area (millions, km^2)	Estimated SOA (t day^{-1})
GTA	6.05, 7,120	67
Greater Houston area	4.1, 5,580	52
Mexico City area	21.2, 7,730	228
Athabasca oil sands	0.061, 844	45–84

Figure 2 | OA mass screens during F1. SOA production is estimated as the sum of the differences in OA transfer rates between screens[18]. The overall rate from the source region (S) is the integrated OA transfer rate through screen D (4.7 t h^{-1}). SOA formed within ~1 photochemical day for major North American metropolitan areas is shown in the table, compared to the range downwind of the OS (F1, F2, F3). Using ΔOA/ΔCO to derive SOA for cities has been estimated to carry −50% to +100% uncertainties[23]. GTA, Greater Toronto Area. Map data: Google, image Landsat, Cnes/Spot Image 2015.

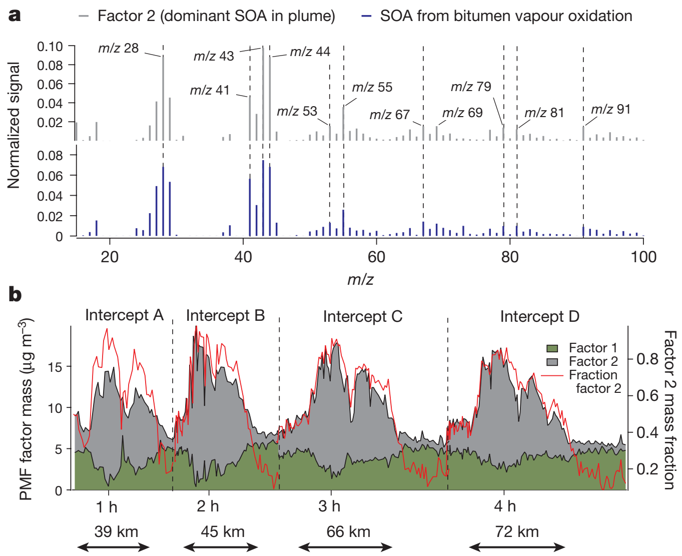


Figure 3 | PMF analysis for F1. a, PMF factor 2 profile during F1 compared to the mass spectra of SOA from the oxidation of bitumen vapours in a smog chamber, demonstrating a high degree of similarity ($r^2 = 0.96$). Signal is normalized to the total aerosol mass spectrometry (AMS) signal. **b,** Factor time series during F1 for consecutive plume intercepts approximately 1 h apart, at 600 m altitude. Factor 2 dominates the aerosol mass within the plume (red curve).

in this volatility range in plumes from OS facilities (Extended Data Fig. 6 and Supplementary Methods).

The bitumen SVOC and IVOC conversion to SOA in the observed plumes was further assessed with a Lagrangian box model constrained by the airborne measurements (Fig. 4c). The model simulated the formation of SOA in the plume of F1 over 3 h (screen A to D; Extended Data Fig. 2). Further details of the box model inputs and outputs are provided in Methods. From the ~70 p.p.b.v. of total VOCs measured at screen A, Fig. 4 demonstrates that only <6% of the SOA after 3 h was contributed by the oxidation of speciated alkanes, alkenes and aromatic hydrocarbons, and <9% by isoprene and monoterpenes. The observed OA can only be reproduced by including bitumen SVOCs and IVOCs with the VD of Fig. 4a at 20 °C; adding 3–4.5 p.p.b.v. of bitumen SVOCs and IVOCs (with the current SOA ageing scheme used) at screen A adequately simulated the SOA measurements after 3 h (contributing ~86% of the SOA; Fig. 4c). Hence, even though the required SVOC and IVOC concentrations may be small (3–4.5 p.p.b.v.) compared to ~70 p.p.b.v. for VOCs, they dominate the contributions to SOA formation. Such a high SOA formation intensity is in contrast to most other types of energy production, which are likely to have emissions in a much lighter hydrocarbon range[28,29].

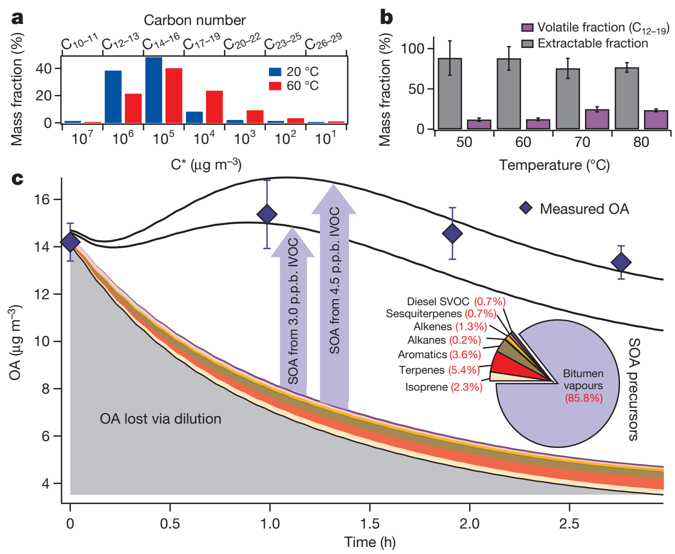


Figure 4 | Modelling SOA formation during F1. a, Volatility distribution of bitumen vapours at 20 °C and 60 °C. **b,** Fraction of the OS that is non-volatile (grey) and the volatile fraction (purple). Error bars represent standard deviation (s.d.) of $n = 3$ experiments. **c,** Box modelling of SOA formation during F1. A discrepancy between measured and modelled OA is reconciled by including 3.0–4.5 p.p.b.v. of bitumen IVOC vapours at time = 0 h (blue arrows). Error bars represent s.d. of the measured OA ($n = 7$). The pie chart indicates the contribution by each precursor type to the mass of SOA after 3 h.

The evidence here indicates that large amounts of SOA will form from this previously unrecognized pool of OS-emitted SVOCs and IVOCs, dominating over SOA from traditional VOC precursors. The potential air-quality impacts of these vapours as a result of transport and refining could be more widespread than anticipated. Indeed, recent evidence indicates that primary IVOCs from an unknown petroleum-based source can account for about 30% of SOA mass in urban/suburban areas[12]. This issue is not limited to Canada, as Venezuela plans to develop its Orinoco Oil Sands recoverable reserve of ~300 billion barrels, and the USA—having an estimated 54 billion barrel reserve of bitumen—has begun surface mining in Utah. In light of the current trend for increasing heavy oil production relative to conventional crude, further investigation is required to fully understand the magnitude of this potential global issue.

Online Content Methods, along with any additional Extended Data display items and Source Data, are available in the online version of the paper; references unique to these sections appear only in the online paper.

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Supplementary Information is available in the online version of the paper.

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Author Contributions All authors contributed to the collection of observations in the field, in the laboratory or the development of the box model. J.L. and S.-M.L. wrote the paper with input from all co-authors. S.-M.L. designed and directed the flights. Y.M.T. and C.S. conducted the box modelling work with input from J.L. D.R.G., D.P., B.D.D. and P.L. provided bitumen volatility distributions.

Author Information The data used are available on the Canada-Alberta Oil Sands Environmental Monitoring Information Portal (http://jointoilsandsmonitoring.ca/default.asp?n=5F73C7C9-1&lang=en). Reprints and permissions information is available at www.nature.com/reprints. The authors declare no competing financial interests. Readers are welcome to comment on the online version of the paper. Correspondence and requests for materials should be addressed to J.L. (John.Liggio@canada.ca) or S.-M.L. (Shao-Meng.Li@canada.ca).

METHODS

Aircraft campaign. Airborne measurements of an extensive set of air pollutants over the Athabasca oil sands region in northern Alberta were conducted between 13 August and 7 September 2013 in support of the Joint Canada-Alberta Implementation Plan on Oil Sands Monitoring. Instrumentation was installed aboard the National Research Council of Canada Institute for Aerospace Research (NRC Aerospace) Convair-580 research aircraft. The aircraft flew 22 flights over the Athabasca oil sands, for a total of approximately 84 h. Thirteen flights were designed specifically to quantify area emissions from various OS facilities by flying in a rectangular box shape, at multiple altitudes, resulting in 21 box flights around 7 different OS facilities.

A further three flights (denoted F1 (4 September), F2 (5 September) and F3 (19 August)) were designed to study the transformation of OS emitted pollutants, including the formation of SOA. These flights were designed as Lagrangian experiments in which the same air parcels in OS plumes were sampled at different time intervals (1 h apart) as the air parcels were transported downwind for 4–5 h. The measurement locations for the flight tracks were chosen so that the aircraft would intercept the same air parcel, using real-time wind speed/direction measurements to guide the intercept locations. The intercepting flight tracks were perpendicular to the axis of the plumes, and the flight times crossing the plumes were 5–7 min. At each intercept location, high time resolution (1 s for gases, 10 s for AMS measurements) measurements were made at multiple altitudes (2–5 horizontal transects) from ∼150 m above ground to over 1,400 m, which was higher than the mixed layer height, consisting of level flight tracks and spirals at the centre of the plume. These vertically spaced level flight tracks and spirals constituted virtual screens at the intercept locations. The three flights (F1, F2 and F3) comprised 5, 3 and 3 screens, respectively. In between the screens in each flight, there were no industrial emissions. Thus, changes between screens can be described in terms of mixing/dilution, chemistry and deposition that occurred from within a single air parcel.

The first screens of the F1, F2 and F3 flights were approximately 1 h downwind of the majority of OS facilities, and at distances that pollutants from multiple OS sources were well mixed and merged into large plumes. The flight paths and their associated parameters are given in Extended Data Fig. 1 and Supplementary Table 1. As shown in this figure, the Lagrangian experiments resulted in varying degrees of success for a number of reasons, including data capture rates, consistency of winds, and the exact timing of when the aircraft crossed the plumes at the chosen intercepting locations, with F1 having the best matches between the air parcel transport times and the aircraft flight times at the screen locations. As a result, the data from F1 are used more extensively than others here, although not exclusively.

The Convair-580 was equipped with fast response instrumentation to measure an extensive set of gas- and particle-phase pollutants, as well as standard meteorological and aircraft state parameters. A description of the meteorological variables and aircraft state parameters measured is given elsewhere[18]. Non-refractory (NR) particle composition (that is, ammonium, nitrate, sulfate and organics) was measured with an Aerodyne high-resolution time-of-flight aerosol mass spectrometer (HR-ToF-AMS; Aerodyne Research)[30]. Refractory black carbon (BC) particle measurements were made with a Single Particle Soot Photometer (SP2; Droplet Measurement Technologies)[31,32]. A subset of volatile organic compounds (VOCs) was measured with a high-resolution proton transfer time-of-flight mass spectrometer (PTR-ToF-MS; Ionicon Analytik GmbH)[33] and a more extensive set of hydrocarbons was measured via on-board canister sampling, followed by analysis by gas chromatography mass spectrometry and flame ionization detection (GC–MS and GC-FID). A full description of all the relevant gas- and particle-phase instrumentation aboard the aircraft is provided in the Supplementary Information. No statistical methods were used to predetermine sample size.

OA mass transfer rate and OS SOA production rate calculations. The quantification of the mass transfer rate of organic aerosols (R_{OA}, in t h^{-1}) across a virtual screen uses an extension of the top-down emission rate retrieval algorithm (TERRA) described previously[18]. TERRA was originally developed to determine emission rates from box flight patterns during this study[18], based on mass balance within the virtual box constructed from the flight tracks. Briefly, TERRA uses the flight path around a facility at multiple altitudes to map the data to the two-dimensional virtual walls of a box surrounding the facility. The transport of a pollutant through the walls is calculated using aircraft wind and compound mixing ratio measurements, and emission rates calculated on the basis of the divergence theorem with estimations of box-top loss rates, horizontal and vertical advective and turbulent transport rates, surface deposition rate, and apparent loss rates due to air densification and chemical reaction rates. For the transformation flights, some components of TERRA were extended to apply to single screens created from vertically stacked level flight tracks and spirals. Concentration data C (in μg m^{-3}) are mapped to the screens and interpolated using a simple kriging function (on approximately 5,000–15,000 individual data points). Wind speed along the flight tracks was decomposed into two components based on the wind direction, one parallel to the screen (u_p) and the other normal to the screen (u_n), and the decomposed wind speeds were similarly mapped to the screen and interpolated using kriging. The lowest flight altitude was at approximately 150 m, hence there was a need to extrapolate the OA measurements and the wind speed components downward to the ground surface. The downward extrapolation for the wind speed components assumed a stability-dependent log profile[34] vertically and uses nearby concurrent wind profiler data to determine the roughness and displacement height[18]. The OA measurement downward extrapolation was based on the assumption of a well-mixed layer below the lowest flight track altitude, which is consistent with modelling[35] and the potential temperature profile. A variation to this downward extrapolation method assumed a linear downward trend from the flight altitudes, to capture possible variations in the mixing state below the lowest flight track altitude. Previous analysis has shown that unknown pollutant concentrations below the lowest flight level (and the associated extrapolation to ground) led to the majority of the uncertainty in the emissions estimates from this approach (∼20%; ref. 18). The OA measurements during the flights here were extrapolated downward using both methods; varying linearly to the ground or held constant (at the lowest altitude concentration) to the ground, to assess the uncertainty in the final derived mass transfer rate caused by the extrapolation methods. The OA data were further linearly extrapolated from the highest altitude level flight tracks upwards (to background OA concentrations) in the case where the level flight tracks did not traverse vertically beyond the mixed layer. The highest altitude extrapolated to was determined from the OA measurements and temperature profiles from spirals along the tracks, which were flown above the top of the boundary layer but not included in the screens. The results showed a difference of <15% for the mass transfer rates among the different extrapolation schemes.

The mass transfer rate of OA across each screen (R_{OA}) of flights F1, F2 and F3 was derived on the basis of the extended TERRA as described earlier and the HR-ToF-AMS data. To avoid the background OA affecting the computation of R_{OA}, a background OA (Extended Data Fig. 7) was subtracted from the OA measurements in the following computation:

$$R_{OA}(A) = \int_{S_1}^{S_2}\int_{Z_1}^{Z_2} C(s,z,A)\,u_n(s,z,A)\,\mathrm{d}s\mathrm{d}z \quad (1)$$

where s_1 and s_2 are the horizontal edge positions on the screen for the plume containing OA, z_1 is the ground surface altitude, z_2 is the top of the plume, $C(s,z,A)$ is the interpolated/extrapolated concentration on screen A (and other screens), and $u_n(s,z,A)$ is the interpolated/extrapolated wind speed vector normal to screen A. The plume edges are determined by the OA concentration on the screen, indicated by $C(s,z,A)$, approaching the background concentration of approximately 4 μg m^{-3}. Note that equation (1) describes horizontal advective transfer rates only; additional contribution from horizontal turbulent fluxes can contribute to R_{OA} but this has been shown to be a few orders of magnitude smaller than the horizontal advective transfer[18] and therefore is ignored henceforth.

Between screens, the mass transfer rate R_{OA} may change due to emissions with a rate of E_{OA}, deposition with a rate of D_{OA}, and the formation of SOA at a rate of R_{SOA}. In the original TERRA, vertical advective and turbulent transfer rates as well as air density changes were considered to achieve mass balance when the background level of a compound was large[18]. The vertical transport term was nominally small compared to the horizontal advection, and hence can be ignored. Thus, using a mass balance approach, the following relationship can be established

$$R_{OA}(t_2) = R_{OA}(t_1) + R_{SOA} + E_{OA} - D_{OA} \quad (2)$$

where t_1 and t_2 are the times of the two screens where the plume parcels were intercepted. Positive matrix factorization (PMF) analysis of the HR-ToF-AMS data from the transformation flights F1, F2 and F3 showed no hydrocarbon-like aerosol factor[25], suggesting small-to-non-existent contributions from primary emissions of organic aerosols between the screens or from the source region to the screens. Hence $E_{OA} = 0$. Using concurrent refractory BC measured by SP2, the maximum dry deposition of BC over the region was estimated to be approximately 7% h^{-1} derived from the differences in the BC mass transfer rates across the screens. We assume that this rate of deposition of BC is applicable to OA. Since deposition derived this way is relatively small, it is ignored to derive the SOA formation rate according to

$$R_{SOA} \approx R_{OA}(t_2) - R_{OA}(t_1) \quad (3)$$

Equation (3) was used to calculate the SOA formation rates, ignoring the dry deposition term, to be comparable to urban SOA estimates, which are net of deposition. Including a fully evaluated dry deposition for the R_{SOA} calculation would mean that equation (3) gives a lower limit of the true SOA formation rate during the measurement period. The total SOA production rate (R_{SOA}) in these flights is taken to be the

OA transfer rate (R_{OA}) through the final screen, since $E_{OA} = 0$ and only oxygenated PMF factors were observed. The total SOA is then extrapolated to a photo-chemical day as described in Supplementary Discussion (Extended Data Fig. 8).

Box modelling description. SOA formation in the large-scale plume of F1 was modelled with a zero-dimensional Lagrangian box model, as it evolved over approximately 3 h (∼600 m altitude). The simulation was constrained by the measurements of VOCs, NO_x, OVOCs, O_3 and other parameters, while dilution within the plume was accounted for using BC as a dilution tracer. Hydrocarbons of both anthropogenic and biogenic origin were constrained at the first screen (A), or throughout the simulation for those biogenic species with potential continuous emissions along the flight track (monoterpenes and isoprene). Background concentrations were constrained by measurements outside of the plume. The model uses the Statewide Air Pollution Research Centre (SAPRC07) chemical mechanism with updated isoprene chemistry[36–38]. The model was run with a 2 min time step and diluted chemical species at every time step. While the model had VOCs constrained, including a constraint for NO_x and O_3 resulted in very little difference between the model and observations. Hence, the gas-phase chemistry is well simulated by the box model, as shown in Extended Data Fig. 9. Sesquiterpenes were constrained based on the ratio to measured monoterpenes. Sesquiterpenes were estimated from the PTR-ToF-MS measurements using an estimated ion transmission efficiency and proton transfer reaction kinetics, in a manner described previously[39,40], resulting in a sesquiterpene:monoterpene ratio of ∼0.39. This is somewhat higher than the ratios of 0.013 and 0.105 that have been recommended previously[41,42], and was used as an upper estimate to the sesquiterpene contribution to SOA. Regardless, biogenic VOCs contributed little to the observed and modelled SOA (Extended Data Fig. 10 and Supplementary Discussion). Recent evidence has also suggested that extremely low-volatility compounds (ELVOC) can also form via an auto-oxidation mechanism[43]. This process has been demonstrated to be most relevant in rural and remote regions where OA loading, VOC and NO_x levels are very low, due to competing $RO_2 + NO$ and/or $RO_2 + RO_2$ reactions. Previous data[43] indicate that ELVOC yields are most important at 1 p.p.b.v. NO_x and below. While ELVOC may be an important SOA contributor outside of the OS plumes (where biogenics are abundant and NO_x is low), the amount of NO_x in the OS plumes studied (as well as the OA loading and VOC levels) were far too high (approaching >20 p.p.b.v. NO_x and always greater than 1 p.p.b.v.) for ELVOC formation to be important. Hence, the contribution of ELVOC was not explicitly included in the box model analysis.

Additionally, the model incorporated SOA formation from all known SOA precursors[24] treating SOA formation in two separate volatility basis sets (VBSs) (see supplementary Methods). Following a previously described method[24], a four-bin VBS ($C^* = 1$, 10, 100 and 1,000 $\mu g\,m^{-3}$) treated SOA formation from traditional volatile organic compounds (VOCs), while a second nine-bin VBS ($C^* = 10^{-2}$–$10^6\,\mu g\,m^{-3}$) treated SOA from SVOCs and IVOCs. The four-bin VBS was used for SOA from traditional VOCs including long-chain alkanes (ALK5 in SAPRC07), olefins (OLE1 and OLE2), aromatics (ARO1, ARO2, NAPTH and benzene), and biogenic compounds (ISOP, TERP and SESQ (isoprene, monoterpenes and sesquiterpenes)[24,44] The nine-bin VBS treated 'non-traditional' SOA formed from the oxidation of off-road diesel as well as bitumen vapours having a volatility distribution as shown in Fig. 4a at 20 °C. This volatility distribution was chosen to represent the emissions of these vapours at ambient temperature that would be expected for the first aircraft screen at ∼600 m above ground, assuming that the open-pit mines are the largest contributor to emissions. A contribution by other processes at higher temperature is also possible. Total non-methane hydrocarbon (NMHC) mixing ratios in the plume were estimated based on the emission ratios of CO:NMHC from the heavy hauler diesel engines used in the Alberta OS facilities and the difference between CO in the plume and CO in the background (ΔCO). The emission ratios of SVOCs and IVOCs relative to total NHMC that were reported previously[39] for diesel engines were then applied to the total NMHC to give an estimate of the SVOCs and IVOCs in the plume. Pentadecane was used as a surrogate species for the SVOC and IVOC species from diesel emissions as suggested previously[44].

The model is configured in such a way that the initial reaction of a SOA precursor with OH (or O_3 in the case of ISOP, TERP, OLE1 and OLE2) leads to the formation of a number of less volatile gas-phase species. These less volatile gas-phase species are placed in volatility bins according to fitted chamber results[45]. The species in each of the bins are then allowed to partition between the gas and particle phase in accordance with their temperature-dependent partitioning coefficients[24,45]. To mimic aerosol ageing, the gas phase components in both the VOC SOA (V-SOA) and semi- and intermediate-volatility SOA (SI-SOA) VBS are aged as described previously[24]. Specifically, traditional SOA in the V-SOA VBS is aged according to the Robinson *et al.* scheme[46], while SOA in the SI-SOA VBS is aged according to the more aggressive Grieshop scheme[47]. The Robinson scheme used to age V-SOA adds 7.5% more mass to the SOA during oxidation while moving the species to a volatility bin 10 times less volatile. The Grieshop scheme[47] that was used to age the SI-SOA adds 40% more mass per oxidation but shifts the species to a volatility bin 100 times less volatile. As the majority of the SOA formed in the V-SOA VBS is formed from anthropogenic precursors, V-SOA was aged at a rate of $1 \times 10^{-11}\,cm^3\,molecule^{-1}\,s^{-1}$ (refs 48, 49). The SOA in the SI-SOA VBS was aged using a faster rate of $2 \times 10^{-11}\,cm^3\,molecule^{-1}\,s^{-1}$ (ref. 24). The use of two separate ageing schemes for SOA formation is consistent with the expected differences between product distributions, molecular size and functional groups of different classes of precursor organic compounds. Such an approach has been used successfully on numerous occasions to match SOA observations (see Supplementary Methods). Further model runs were also performed to examine the sensitivity of the SOA formed from IVOCs to the oxidation scheme used (Extended Data Fig. 9 and Supplementary Methods). On the basis of these further model runs, the chosen base case conditions provide the best estimate of the SOA formation rate as it lies between the two upper and lower limits and is consistent with the scheme used in numerous regional air quality models that reasonably reproduce ambient forested and urban observations around the world.

The model output was compared with organic aerosol observations. While the HR-ToF-AMS effectively measures $PM_{1.0}$, the condensation of oxidized products will occur across the entire size distribution. Considerable coarse particle mass is observed during flight 1, probably originating from the large trucks during mining operations. Since the box-model output is a bulk SOA value (that is, size independent), the AMS-derived OA mass is further increased using the measured surface area ratio of $PM_{1.0}$ to PM_{20}, assuming that the condensation process is approximately proportional to surface area. This ratio, which ranged from ∼1.3 to 1.1 from screen A to screen D, was multiplied by the AMS-measured OA, increasing the total OA by 10–30% for comparison to the model output.

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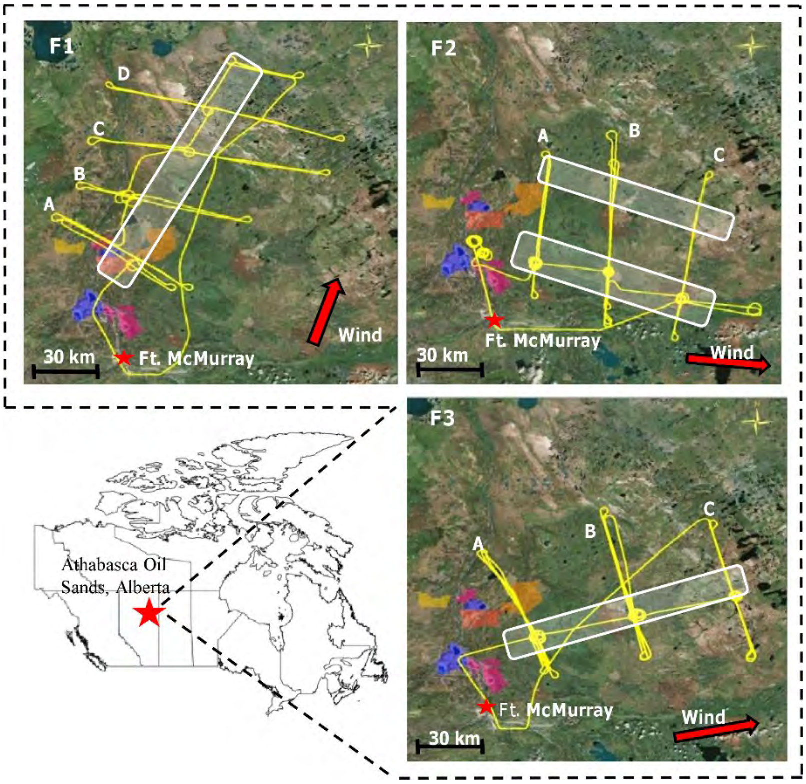
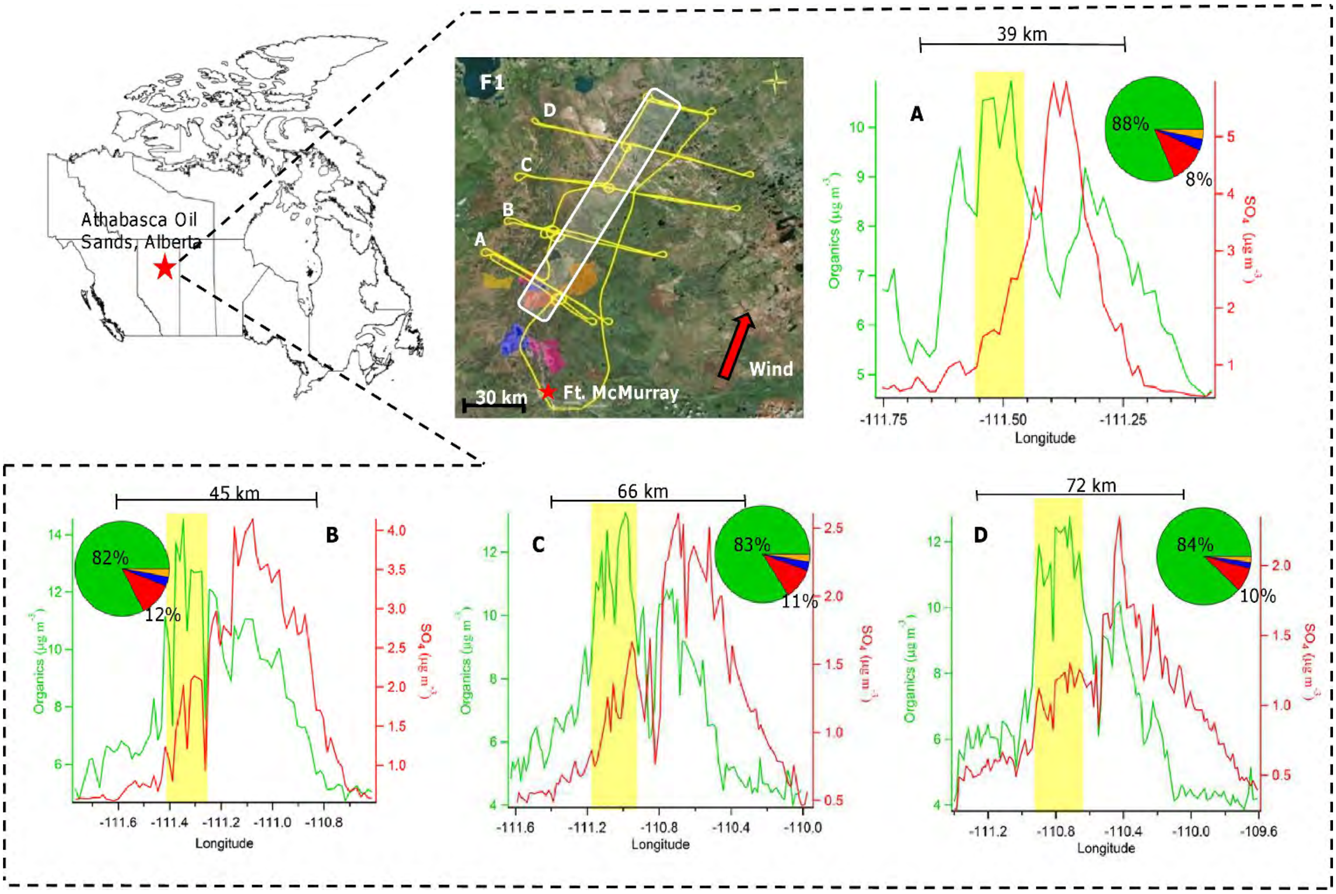
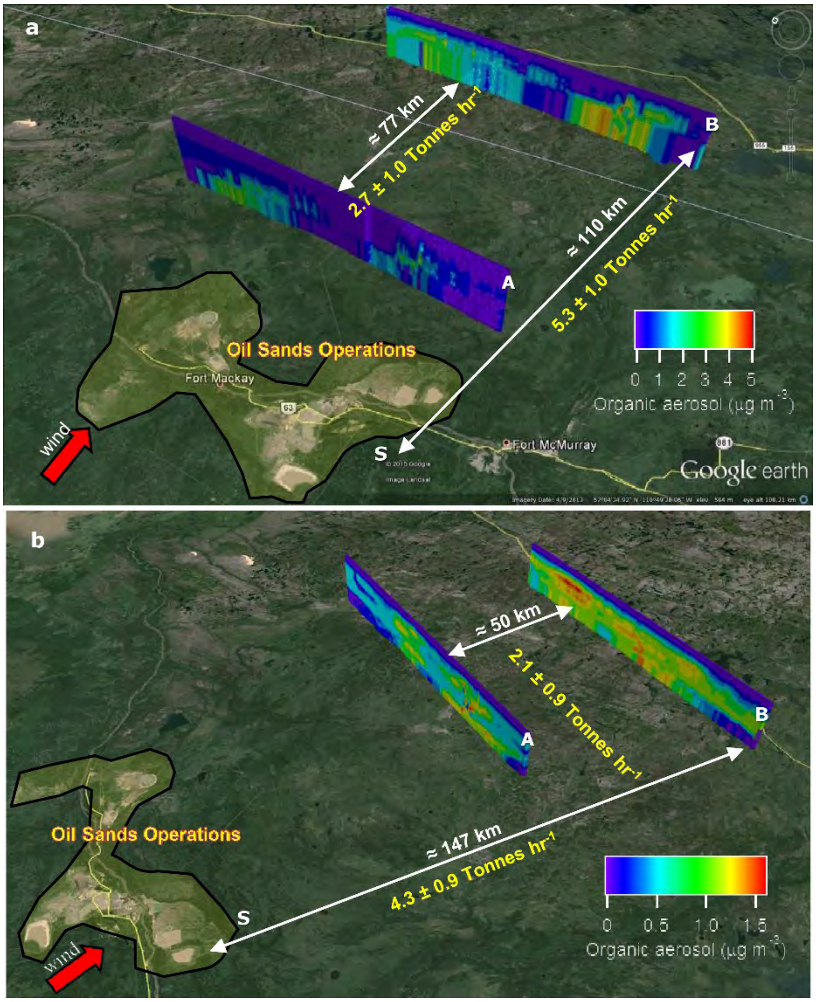


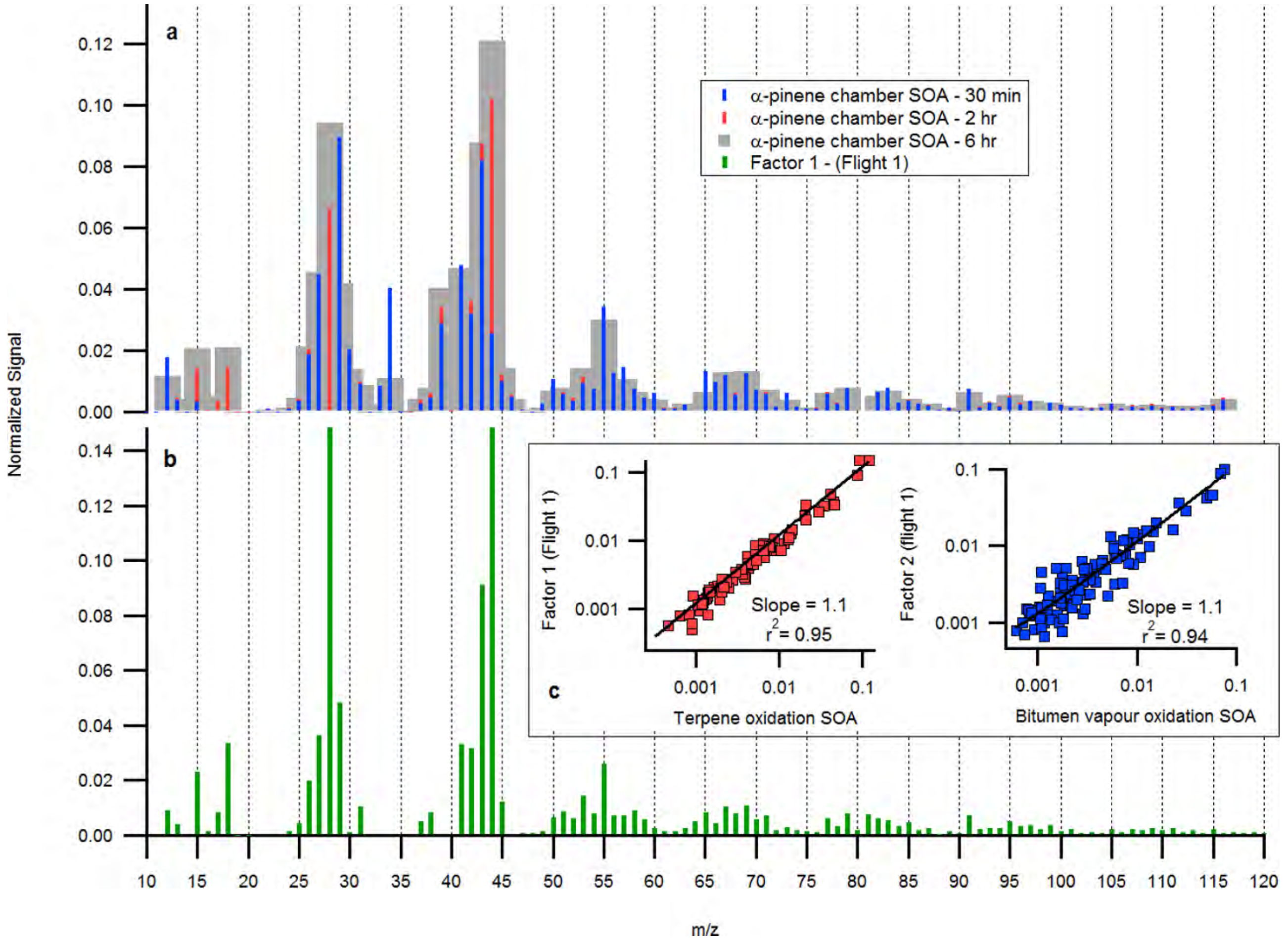
Extended Data Figure 1 | Flight tracks for the three transformation flights, F1, F2 and F3. The approximate locations of the major OS plumes studied in this work are shown as the white shaded boxes. Map data: Google, image Landsat, 2015.



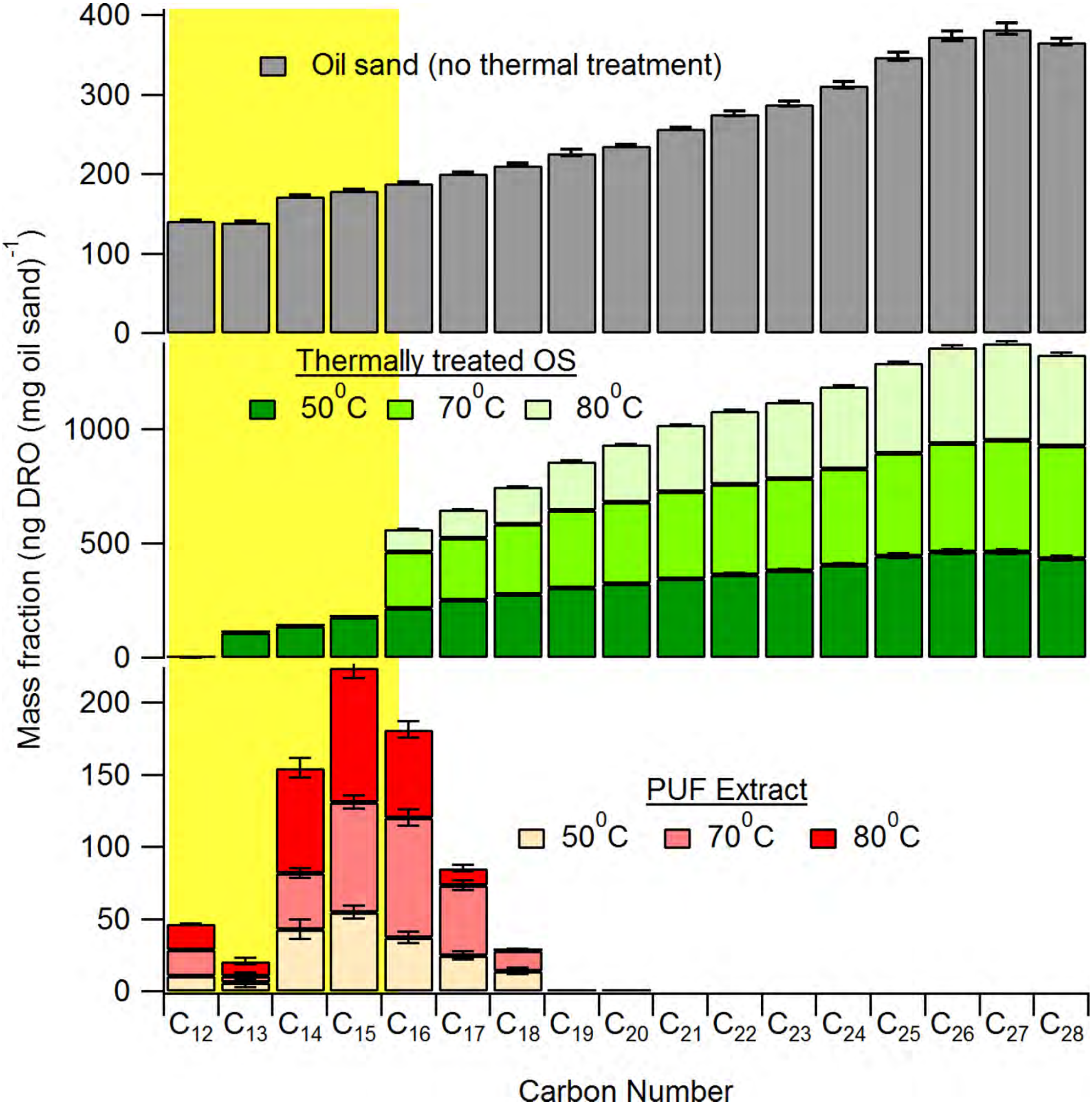
Extended Data Figure 2 | Measured organic and sulfate aerosol concentration during F1. Successive transects (labelled A, B, C and D) through the same major OS plumes at approximately 600 m altitude and 1 h apart in transit time. Inset pie plots show the mean relative mass fraction for organics (green), sulfate (red), nitrate (blue) and ammonium (orange) during the yellow highlighted section. Organics dominate the aerosol mass throughout the flight; note the change in magnitude between the OA scale on the left and SO_4 scale on the right. Map data: Google, image Landsat, 2015.



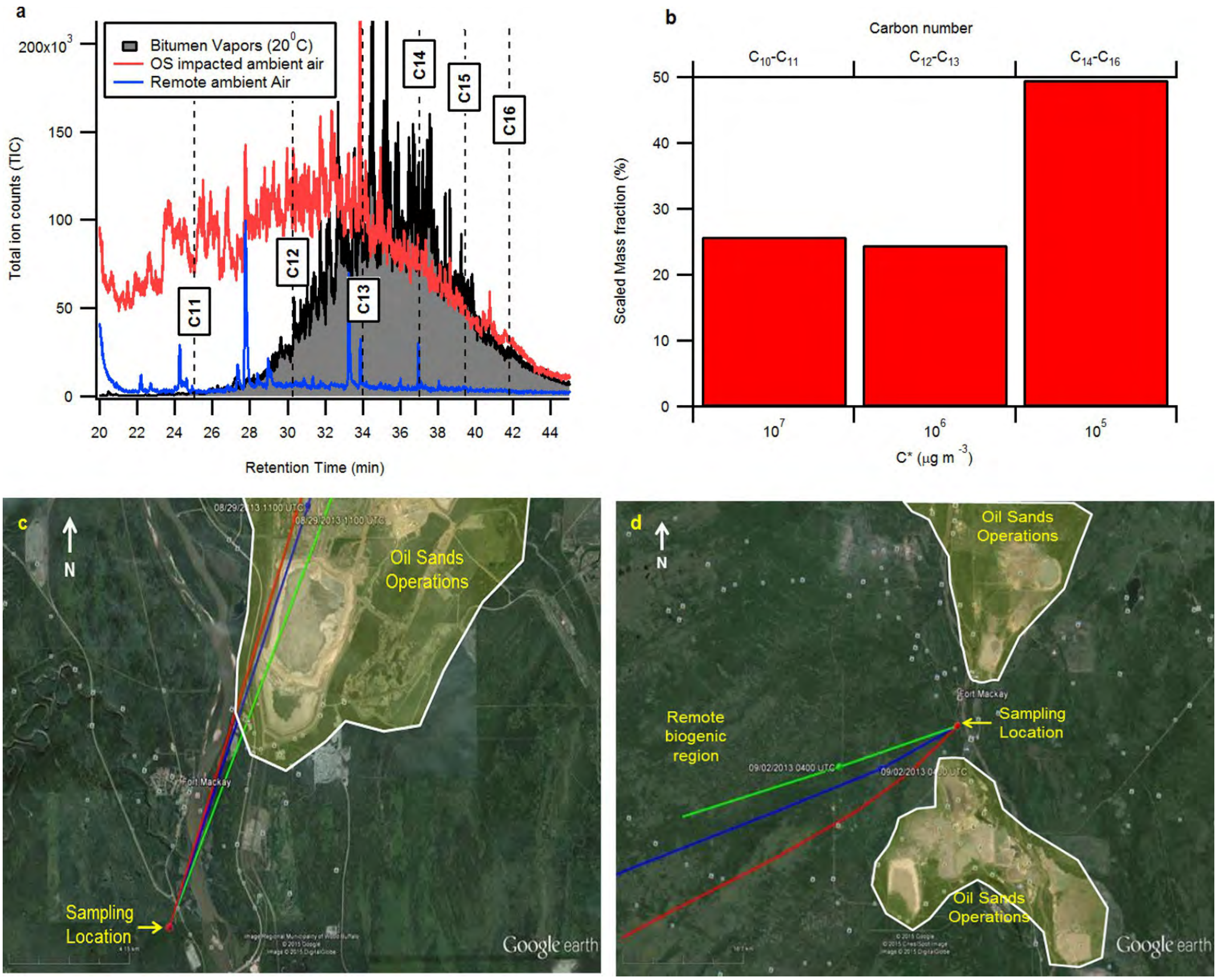
Extended Data Figure 3 | OA mass screens used to estimate SOA production. a, **b**, OA mass screens for F2 (**a**) and F3 (**b**). The SOA production rate during these flights (~77 km and ~50 km between screens) is the sum of the differences in OA transfer rates between screens (that is,: $2.7 \pm 1.0\,\mathrm{t\,h^{-1}}$ and $2.1 \pm 0.9\,\mathrm{t\,h^{-1}}$). The overall formation rate from the OS source region (S) is the integrated OA transfer rate through screen B ($5.3 \pm 1.0\,\mathrm{t\,h^{-1}}$ and $4.3 \pm 0.9\,\mathrm{t\,h^{-1}}$). Map data: Google, image Landsat, 2015.



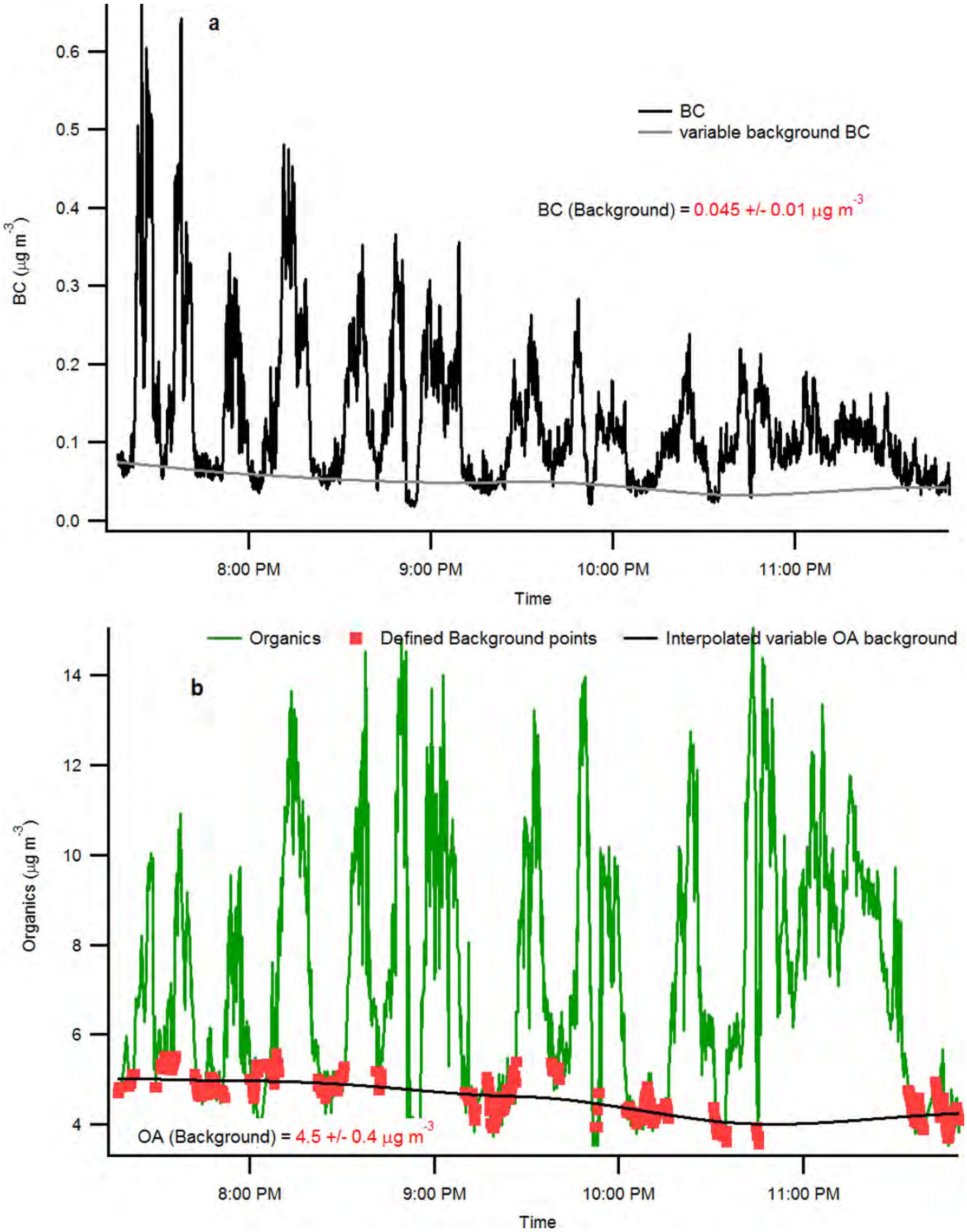
Extended Data Figure 4 | PMF analysis results and comparisons. **a**, The OA AMS spectra from an α-pinene + OH radical smog chamber experiment as a function of photochemical ageing time in the chamber. **b**, PMF factor 1 from F1. A high degree of similarity is observed between these spectra after approximately 6 h of ageing in the chamber. **c**, Correlations between PMF factors 1 and 2 and the corresponding smog chamber data (terpene oxidation and bitumen vapour oxidation SOA).



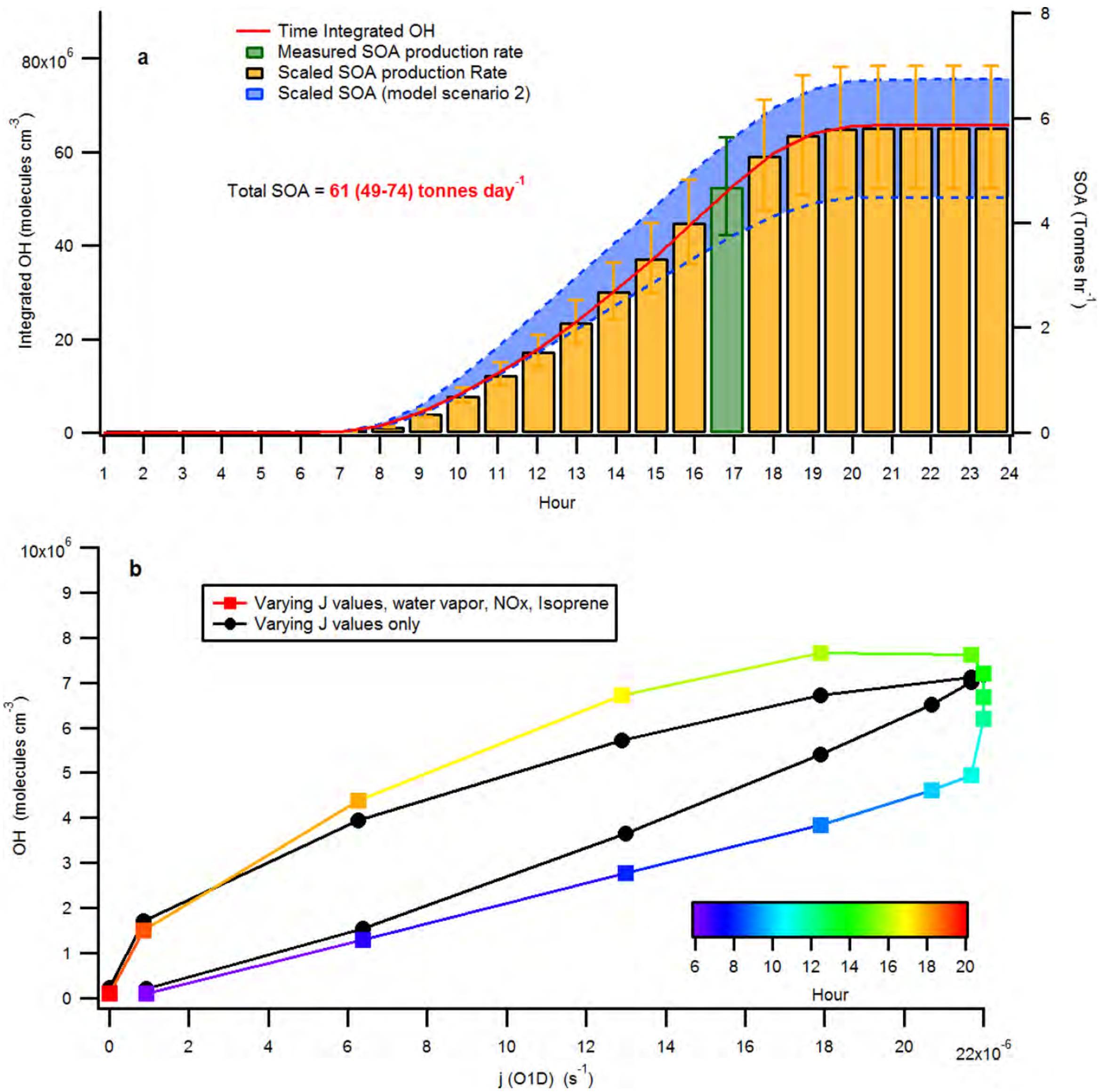
Extended Data Figure 5 | Bitumen volatility distributions. The volatility distribution (mass fraction) based on carbon number are for OS that was thermally treated. Volatile hydrocarbons are trapped on polyurethane foam (PUF) tubes at 50–80 °C (red). The volatility of the remaining bitumen material is shown in green (50–80 °C) and that of bitumen which was solvent extracted from the sand without heating is shown in grey. Note the complete loss of hydrocarbons in the C_{12}–C_{15} range upon heating (denoted in yellow). Data are stacked upon each other for clarity. Error bars represent the s.d. of $n = 3$ experiments.



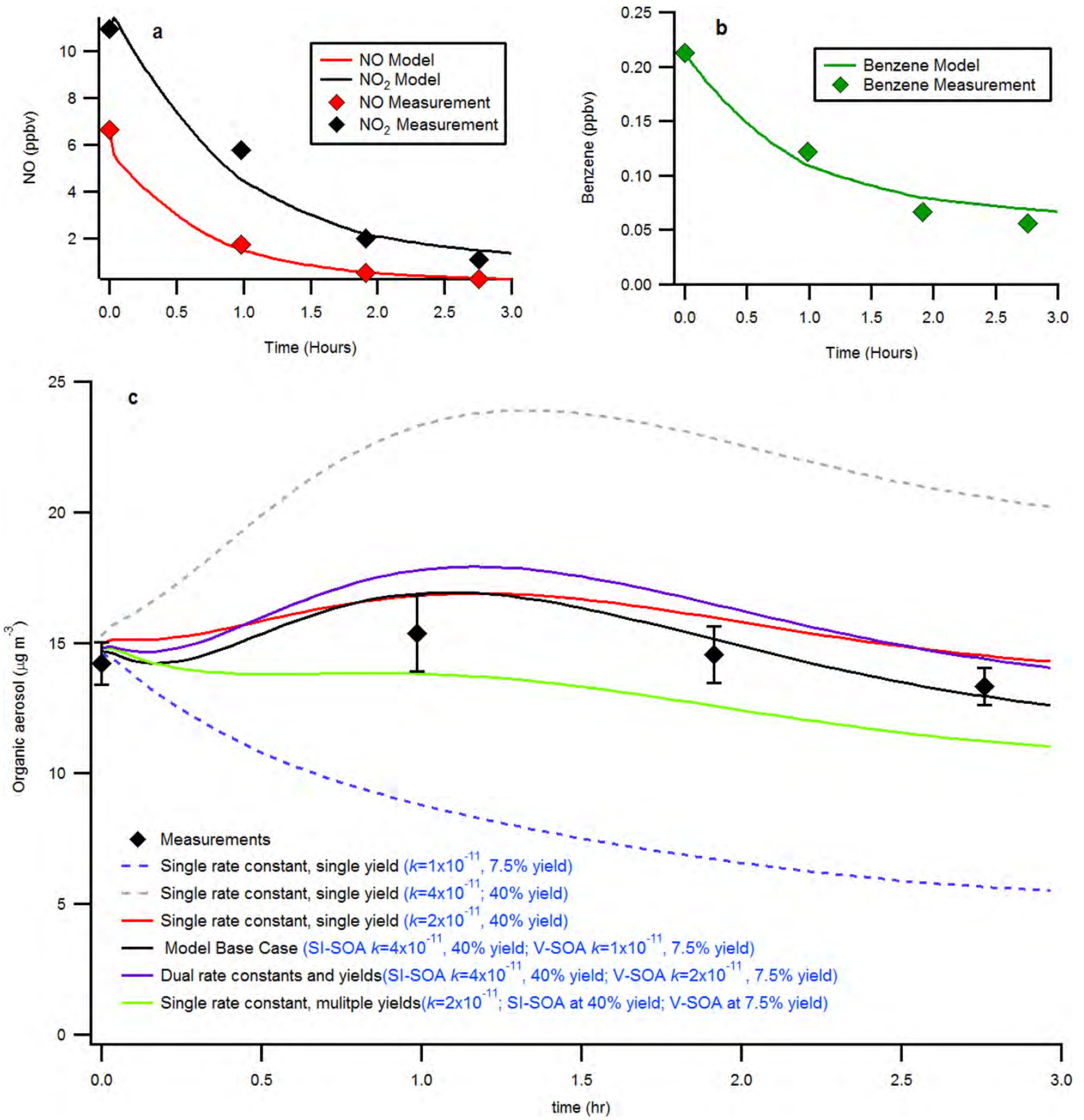
Extended Data Figure 6 | Bitumen-related IVOCs in ambient ground-based data. a, Total ion chromatogram from ambient sampling in the OS when impacted by forest-influenced air (blue) and OS-operations air (red). The bitumen vapour headspace chromatogram is also shown (black), demonstrating that a large fraction of the gaseous mass in OS-impacted air has volatilities (C_{13}–C_{16} range) critical for SOA formation. **b**, Associated volatility distribution for OS-impacted air scaled by SOA yield[11]. **c**, One-hour back trajectory for OS-impacted sample using the hybrid single particle Lagrangian integrated trajectory model (HYSPLIT). **d**, One-hour HYSPLIT back trajectory for forest-influenced sample.



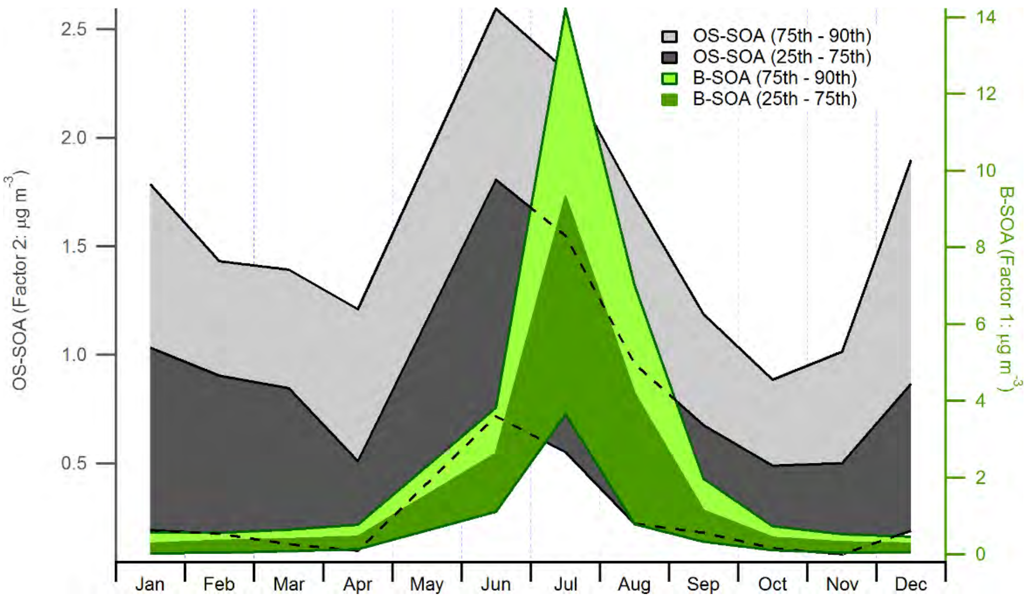
Extended Data Figure 7 | Background concentration time series. a, **b**, The BC (**a**) and OA (**b**) time series for F1 with associated interpolated backgrounds. The background variability contributed little uncertainty to the overall analysis of ΔOA/ΔBC in Fig. 1.



Extended Data Figure 8 | SOA production rate extrapolation. **a**, Measured SOA for F1 extrapolated to one photochemical day. Total SOA production is the sum of scaled hourly SOA production rates (orange; see Supplementary Methods). The blue region represents the same scaling performed where only photolysis rate constants are varied in the model. Error bars represent a range of SOA estimates assuming ±20% on the initial OA estimates via the TERRA algorithm. **b**, Modelled dependence of OH radical concentration on the ozone photolysis frequency (JO^1D). Further varying initial conditions for NO_x, water vapour and isoprene in the model has a small effect on this relationship.



Extended Data Figure 9 | Box-model performance evaluation. **a**, **b**, Measured and modelled gas-phase species during plume intercepts of F1, where only the initial conditions ($t = 0$) of the species are constrained by measurements. Good agreement between model and observation is achieved. **c**, Sensitivity of predicted SOA for F1 to changes in the oxidation rate constant and yield (all other variables remain constant). Yield refers to the SOA mass yield during the oxidative ageing. Simulations using a single oxidative rate constant and yield represent upper and lower limits to SOA formation, while the base case simulation most closely resembles measurements. Error bars represent s.d. of the measured OA ($n = 7$).



Extended Data Figure 10 | PMF factors from ground-based data in the OS. PMF factors 1 (biogenic SOA (B-SOA)) and 2 (OS-SOA) from 1 year of ground-based data in the OS production region (monthly 25th to 90th percentiles shown, $n = 22{,}280$), indicating that factor 2 (using a collection efficiency of 1) is derived from the oxidation of OS emissions all year long, while factor 1 is from oxidation of biogenic emissions (that is, summer peak only).

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TECHNICAL REPORT

Organic Compounds in the Environment

Formation potential and source contribution of secondary organic aerosol from volatile organic compounds

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Assigned to Associate Editor Jian Zhao.

Abstract

Secondary organic aerosol (SOA), a key constituent of fine particulate matter, can be formed through the oxidation of volatile organic compounds (VOCs). However, information on its relevant emission sources remains limited in many cities, especially concerning different types of land use. In this study, VOC concentration in Bangkok Metropolitan Region (BMR), Thailand, was continuously collected for 24 h by 6-L evacuated canister and analyzed by gas chromatography/mass spectrophotometry following USEPA TO15, and the formation of SOA was evaluated through the comprehensive direct measurements and speciation of ambient VOCs. Finally, source contribution of VOCs to SOA formation was characterized using the Positive Matrix Factorization (PMF) model. The results revealed the abundant group of VOCs species in the overall BMR was oxygenated VOCs, accounting for 49.97–57.37%. The SOA formation potential (SOAP) ranged from 1,134.33 to 3,143.74 μg m^{-3}. The VOC species contributing to the highest SOAP was toluene. Results from the PMF model revealed the dominant emission source of VOCs that greatly contributed to SOA was vehicle exhaust emission. Industrial combustion was the main source of VOC emission contributing to SOA in industrial areas. Sources of fuel evaporation, biomass burning, and cooking were also found in the study areas but in small quantities. The results of this study elucidated that different emission sources of VOCs contribute to SOA with respect to different types of land use. Findings of this study highlight the necessity to identify the contribution of potential emission sources of SOA precursors to effectively manage urban air pollution.

Abbreviations: BMR, Bangkok Metropolitan Region; CMB, Chemical Mass Balance; LPG, liquid petroleum gas; MDL, method detection limit; OVOC, oxygenated volatile organic compound; PMF, Positive Matrix Factorization; SOA, secondary organic aerosol; SOAP, secondary organic aerosol formation potential; TVOC, total volatile organic compounds; VOC, volatile organic compound.

1 | INTRODUCTION

Core Ideas

- Volatile organic compound (VOC) profiles in the megacity were comprehensively identified.
- The origins of secondary ultra-fine particulate were evaluated.
- Contribution of each VOCs to the potential formation of secondary organic aerosol were quantified.

Volatile organic compounds (VOCs) not only play an important role in the process of chemical reactions in the atmosphere but also are classified as air pollution by the USEPA (Sun et al., 2016; Wang, Wang, et al., 2018). Volatile organic compounds are formed by biogenic and anthropogenic sources, and human activities play an important role in VOC emissions within urban areas (Kansal, 2009; Zhao et al., 2021). The major anthropogenic sources of VOCs are traffic, fuel evaporation, paint solvent use, industrial emission, and biomass burning (Song et al., 2019; Vichit-Vadakan & Vajanapoom, 2011). These sources are related to the chemical reactivity of the different VOC species (Hui et al., 2018). Volatile organic compounds are important precursors to secondary organic aerosol (SOA) contributing $PM_{2.5}$ (Dieu Hien et al., 2019; Lonati et al., 2007; Ng et al., 2007). Secondary organic aerosol contributes about 30–77% of $PM_{2.5}$ mass concentrations (Huang et al., 2014). The complex organic mixtures of $PM_{2.5}$ differ depending on meteorology, and $PM_{2.5}$ comprises 45–90% of organic aerosols (Mancilla et al., 2015). Man-made aromatics were the main contributors to secondary organic aerosol potential (SOAP), accounting for 98% of the total (Baltensperger et al., 2005; Q. Li et al., 2020). In addition, the composition of secondary particulate formed by VOCs was about 11–41% of total $PM_{2.5}$ in the United States (Hodan & Barnard, 2004).

In a society with a rapidly growing economy and urbanization coupled with meteorologic factors, air pollution is a prominent environmental problem (Ding et al., 2016). Thailand, one of the developing countries located in the heart of mainland Southeast Asia, is facing a serious air pollution problem. The Thailand National Ambient Air Quality Standard of 24 h set the $PM_{2.5}$ concentration to not more than 50 μg m^{-3}. It was found that the concentration of $PM_{2.5}$ was higher than the standard, which was a problem in episodic terms; the concentration is high at certain intervals but is not continuous throughout the year. This problem is spread across almost all areas of Thailand, with cause, extent, and severity varying in each area. In 2015, Saraburi province was reported to have the greatest number of days of $PM_{2.5}$ exceeding the standard, followed by Samut Prakan, Lampang, and Bangkok (PCD, 2015). The Air Quality Assessments for Health and Environment Policies in Thailand report elucidated that $PM_{2.5}$ concentrations exceeded the national standard on 353 d from 2012 to 2016 (PCD, 2018b). The World Bank report indicated that Thailand has made great strides in the past decade in addressing air pollution. However, although overall air quality has improved, pollution is still a problem in areas with heavy traffic and in downtown areas (World Bank, 2003).

The Bangkok Metropolitan Region (BMR) is located in the central part of Thailand and includes the captital city Bangkok and five adjacent provinces (Nakhon Pathom, Nonthaburi, Pathum Thani, Samut Prakarn, and Samut Sakhon). The BMR has expanded urbanization rapidly in recent years, causing substantail air pollution. The worst air quality in BMR occurred in 1992 during a period of rapid economic growth that caused particulate matter concentrations to exceed the standard by 10 times (PCD, 2004). The BMR has experienced a sharp increase in air pollution from vehicle emissions, which are attributed to the increasing number of vehicles (Muttamara & Leong, 2000; Uttamang et al., 2018). During January to February 2018 and December 2018 to January 2019, $PM_{2.5}$ concentrations exceeded the standard because of vehicle emissions. Furthermore, meteorological conditions consisting of minimal air circulation and no wind speed contribute to pollution in and around Bangkok. In the past, Thailand faced ambient VOC pollution, which has become a major environmental problem in urban areas (Dieu Hien et al., 2019). The Pollution Control Department reported in 2018 that the annual concentration of VOCs was 1.3–4.7 μg m^{-3}, gradually increasing from the past year (PCD, 2018a). The problem has been classified as an urgent and important topic of the country.

Suwattiga and Limpaseni (2005) studied the seasonal source apportionment of VOCs in Bangkok ambient air. Samples collected during July 2003 to February 2004 were analyzed by thermal desorption gas chromatography–mass spectrophotometry, and the Chemical Mass Balance (CMB7) receptor model was used to identify contribution from various sources to ambient VOC concentrations. Eighteen VOC species were quantified, among which toluene (7.54 μg m^{-3}) was the highest concentration at all stations in Bangkok. The CMB model showed that the largest emission sources were exhaust from gasoline vehicles and diesel vehicles (42%), fuel oil boilers (12%), and gasoline vapor (12%). The source apportionment discovered other important sources, including vapor of paint and thinners, biomass burning, food barbequing, and municipal waste disposal.

However, the CMB model cannot exclude sources with similar chemical composition (Begum et al., 2007), and the major limitation of the CMB model is the uncertainty in emissions components that can change due to various factors (Laowagul et al., 2021). The Positive Matrix Factorization

TABLE 1 Information of the sampling site characteristics

Land use	Sampling site	Province	Geographical location (UTM: km) X	Y
General area	PRD	Bangkok	666.531	1,524.281
	NPWR	Nakhon Pathom	614.325	1,529.422
	LPW9	Nonthaburi	655.375	1,539.793
	BURC	Pathum Thani	673.340	1,552.453
	ERTC	Pathum Thani	685.038	1,553.572
	PPRDC	Samut Prakan	666.934	1,511.107
	SWSC	Samut Sakhon	636.851	1,498.350
Roadside area	DDCF	Bangkok	667.605	1,522.011
	KCNR	Bangkok	652.975	1,507.984
	MUSC	Nakhon Pathom	643.457	1,525.390
	STOU	Nonthaburi	665.918	1,538.070
	EGAT	Nonthaburi	662.805	1,526.903
	RSMO	Pathum Thani	673.478	1,546.883
	SPCH	Samut Prakan	672.707	1,503.893
	SHPB	Samut Sakhon	642.265	1,515.542
Industrial area	RKCC	Nakhon Pathom	638.411	1,518.870
	SBPP	Samut Prakan	668.347	1,506.018
	TNSC	Samut Sakhon	639.794	1,502.030

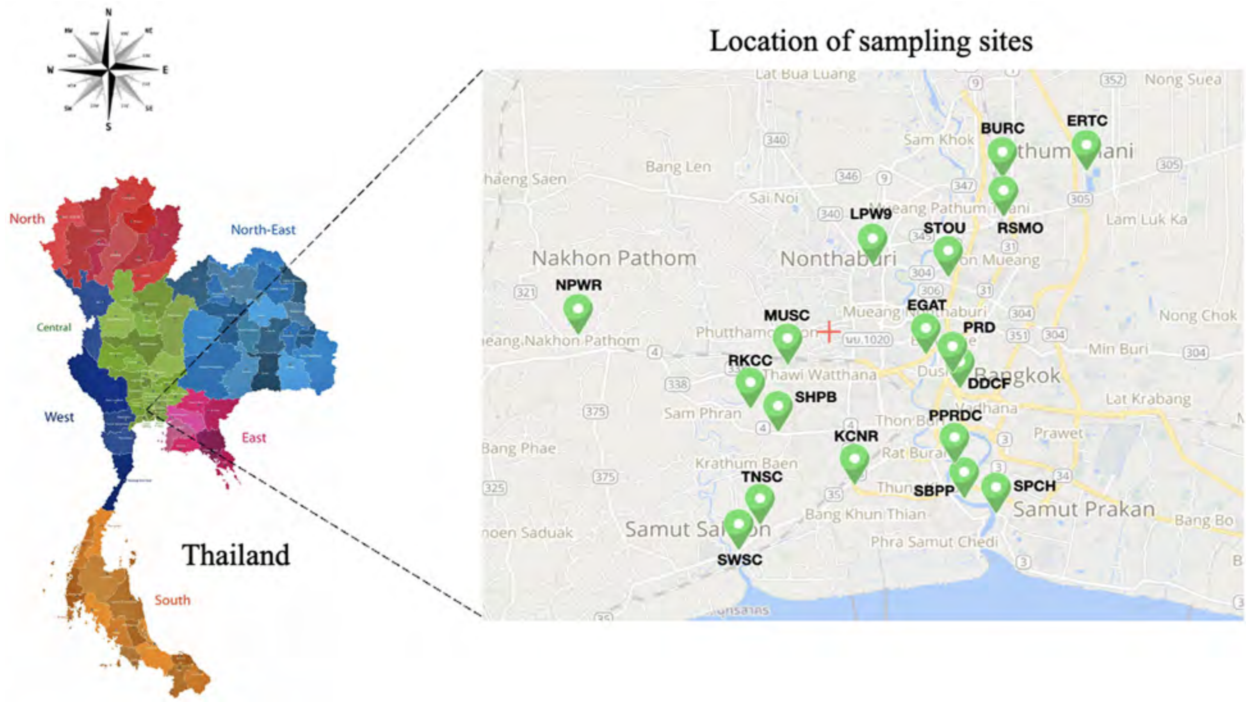

FIGURE 1 Location of the sampling site

(PMF) model has been used widely for identification of sources and their contribution of ambient VOC concentrations (Rai et al., 2016), and the PMF model can identify their sources faster than the CMB model (Pindado & Perez, 2011). Furthermore, the PMF model is suitable for cases where there is insufficient source profile data because it can analyze the source from the correlation matrix of observation data to assess the source contribution.

TABLE 2 Traffic density at each roadside monitoring

Sampling site	Traffic density	Sampling site	Traffic density
	vehicles d^{-1}		vehicles d^{-1}
DDCF	67,000	EGAT	106,000
KCNR	123,000	RSMO	86,000
MUSC	83,000	SPCH	28,000
STOU	120,000	SHPB	42,000

Several studies have presented data regarding formation potential and source contribution SOA from VOCs (Faust et al., 2017; Gao et al., 2021; Zheng et al., 2021). Q. Li et al. (2020) investigated the characteristics of VOCs measured from March 2016 to January 2017 in different seasons and the contribution of VOCs to SOA potential (SOAP) in Beijing, China. All VOC samples were analyzed using a gas chromatography-flame ionization detection system, and the contribution of VOC species to SOA formation was calculated based on SOAP developed by Derwent et al. (2010). The concentration and proportion of VOC species measured in different seasons in Beijing showed that winter had the highest concentration level (126.6 µg m^{-3}), followed by spring, autumn, and summer. Alkanes were the most abundant species for all seasons, contributing 54.1–64.7% of the total. The contribution of VOC species to SOA formation calculated based on SOAP developed by Derwent et al. (2010) showed that the highest SOAP of 2,937.8 µg m^{-3} was observed during winter. Aromatics were the main contributors to SOAP, accounting for 98% of the total. The PMF model was used to analyze source apportionment and indicated that vehicle exhaust was the largest source of VOCs in Beijing, accounting for 19% of the total. Hui et al. (2018) studied VOC characteristics, sources, and contributions to SOA formation during haze events in Wuhan, Central China. They found that the total VOC (TVOC) concentrations measured continuously from October 2016 to November 2016 on severe haze days were 202.66 µg m^{-3} and that SOA formation on haze days, calculated using the equation developed by Derwent et al. (2010), was 1,661–4,542 µg m^{-3}. The dominant contributors to SOAP were aromatics, accounting for 97% of the total. The source apportionment result analyzed by the PMF model indicated that solvent use, vehicle exhaust, and liquid petroleum gas (LPG) usage were the most important sources of VOC pollution during haze events in Wuhan.

There is still a limited number of studies about formation potential and source contribution of SOA from VOCs obtained from intensive direct measurements in the BMR (according to three types of land use: general, roadside, and industrial areas). Therefore, the goals of this study were (a) to estimate the potential of individual VOC species contributing to the SOA formation, (b) to identify type of VOC species

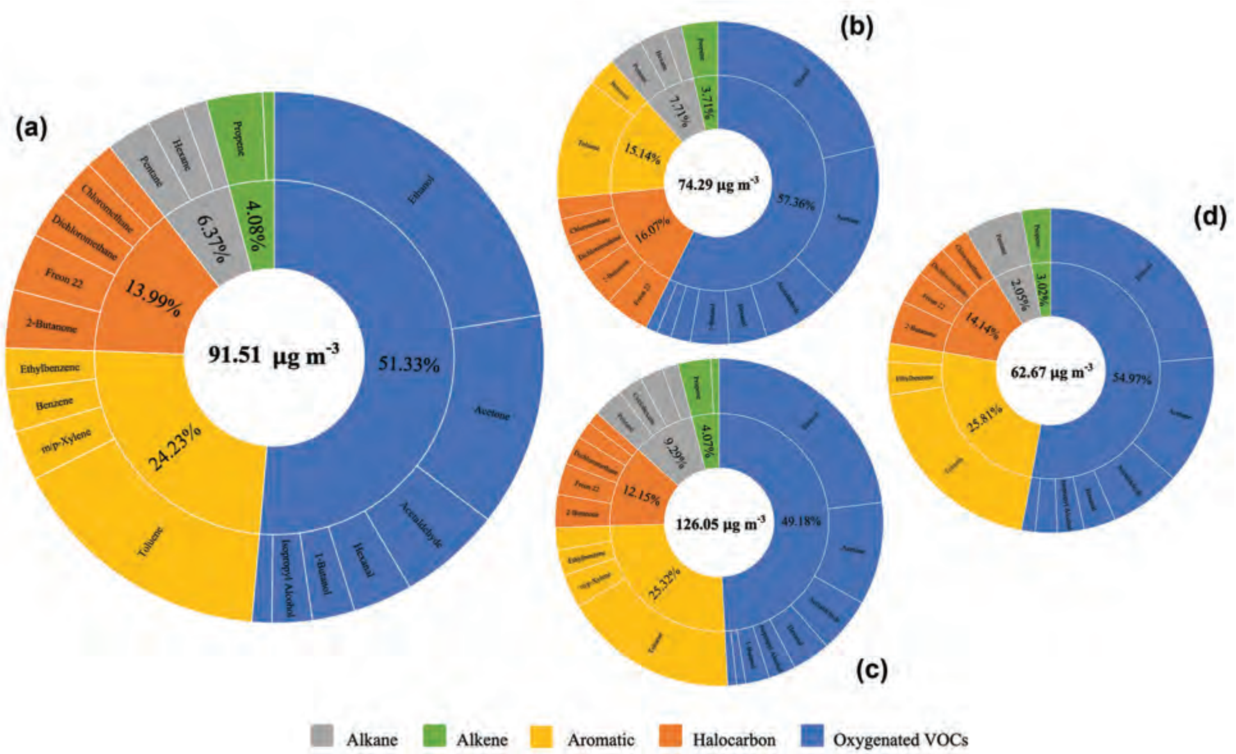

FIGURE 2 Volatile organic compounds (VOCs) composition and species in (a) all land use areas, (b) general area, (c) roadside, area and (d) industrial area

TABLE 3 Comparison of measured volatile organic compound with other studies

Location	Period	Alkane	Alkene	Aromatic	Halocarbon	Oxygenated	Reference
		%					
All land use, BMR, Thailand	Dec. 2020–Feb. 2021	6.37	4.08	24.23	13.99	51.33	this study
General area, BMR, Thailand	Dec. 2020–Feb. 2021	7.71	3.71	15.14	16.07	57.37	this study
Roadside area, BMR, Thailand	Dec. 2020–Feb. 2021	9.29	4.07	25.32	12.15	49.18	this study
Industrial area, BMR, Thailand	Dec. 2020–Feb. 2021	2.05	3.02	25.82	14.14	54.98	this study
Zhengzhou, China	May 2018	31.26	10.77	5.7	20.81	31.47	Q. Li et al. (2020)
Beijing, China	2016	39.93	12.92	8.36	11.73	27.11	Liu et al. (2020)
Wuhan, China	Nov. 2016–Aug. 2017	49.69	13.09	10.09	11.69	15.44	Hui et al. (2018)
Seoul, South Korea	Jan. 2018–Jan. 2019	68.16	14.09	16.85	–	–	Kang et al. (2022)
Paris, France	Jan. 2010–Feb. 2010	40.49	6.04	17.51	–	35.96	Baudic et al. (2016)
Nagoya, Japan	Dec. 2003–Nov. 2004	11.84	67.66	20.48	–	–	Saito et al. (2009)

Note. BMR, Bangkok Metropolitan Region; TVOCs, total volatile organic compounds.

affecting SOA formation in different land uses in BMR, and (c) to evaluate source contribution of VOCs contributing to SOA formation. A PMF model, a receptor-oriented modeling tool, was applied to identify the contributing sources of VOCs affecting SOA formation.

2 | MATERIALS AND METHODS

2.1 | Sampling site description

This study was conducted in the BMR, located in the central region of Thailand, comprising six provinces: Bangkok, Nakhon Pathom, Nonthaburi, Pathum Thani, Samut Prakan, and Samut Sakhon. The study area was characterized by three different types of land use. The 18 sampling sites included seven sites in general areas, eight sites in roadside areas, and three sites in industrial areas. Characteristics and spatial locations of VOC sampling sites are shown in Table 1 and Figure 1. Criteria to determine the type of land use in the study areas were derived from the conditions of the onsite scale (within a radius of 150 m) and local scale (within a radius of 10 km) according to Acid Deposition Monitoring Network in East Asia guidelines (EANET, 2000).

A general area was defined as residential having less traffic density. A roadside area was defined by the area where the traffic density was more than 1,000 vehicles d^{-1} on-site and 5,000 vehicles d^{-1} on a local scale. This traffic information was acquired from the database of the Thai Department of Highway and is presented in Table 2 (DOH, 2020). Sampling sites with factories located around the on-site and local scales were classified as industrial areas. Clearly assessing the formation potential and source of VOCs affecting SOA in each area was possible when dividing the study area by land use type.

2.2 | Sample collection

Direct measurement of ambient VOC concentrations was intensively conducted from 14 Dec. 2020 to 19 Feb. 2021 at 18 sampling sites. Samples of VOCs were continuously collected based on USEPA TO15 for 24 h. Before sampling, stainless steel, 6-L, evacuated Summa canisters used to collect the samples were cleaned with high-purity N_2 and evacuated at 0.05 mm Hg. During the sampling period, canisters were placed at about 5 m vertical height from the ground. When canisters were opened, ambient VOCs were transferred into the canisters by the difference of vacuum pressure inside the canister and the atmospheric pressure. A constant flow rate was acquired from the use of a flow controller adjusted to 3.3 ml min^{-1} for 24-h sampling. Subsequently, the samples

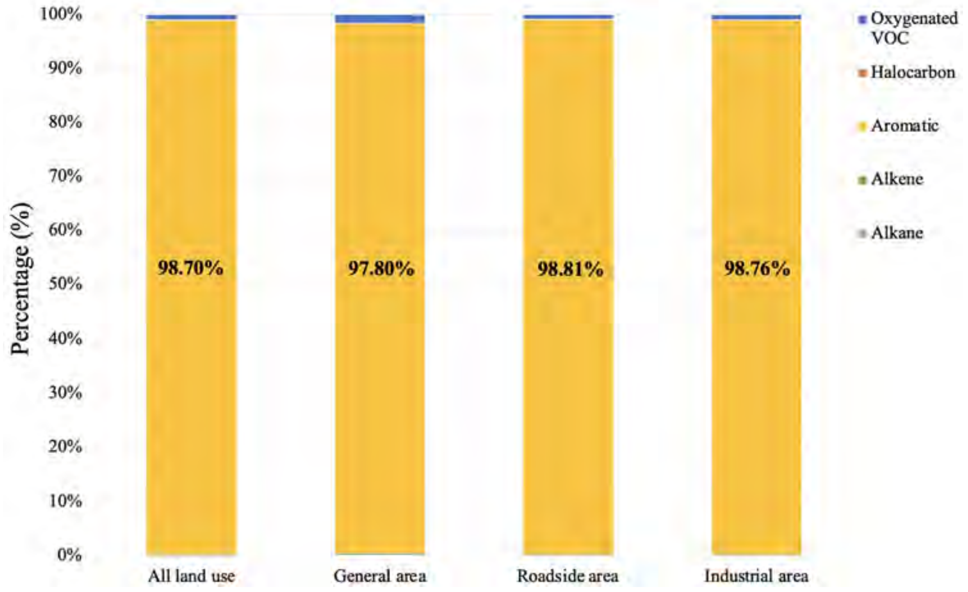

FIGURE 3 Percentages of different volatile organic compound (VOC) groups to the total secondary organic aerosol formation potential

TABLE 4 Top five volatile organic compound (VOC) species contributing to secondary organic aerosol formation potential (SOAP)

Land use	VOC species	Concentration	SOAP	Percent
	———	µg m^{-3}	———	
All types of land use (total SOAP = 2,188.32 µg m^{-3})	toluene	14.73	1,473.11	67.32
	ethylbenzene	2.31	258.29	11.80
	benzene	2.32	215.47	9.85
	m,p-xylene	2.81	212.94	9.73
	ethanol	20.54	12.33	0.56
	total	42.72	2,172.13	99.26
General area (total SOAP = 1,134.33 µg m^{-3})	toluene	9.08	908.02	80.05
	benzene	2.17	201.37	17.75
	ethanol	15.86	9.51	0.84
	propene	2.75	4.41	0.39
	acetone	11.76	3.53	0.31
	total	41.62	1,126.84	99.34
Roadside area (total SOAP = 3,143.74 µg m^{-3})	toluene	21.71	2,170.66	69.05
	ethylbenzene	3.18	355.20	11.30
	m,p-xylene	4.20	318.26	10.12
	benzene	2.82	262.21	8.34
	ethanol	29.02	17.41	0.55
	total	60.93	3,123.75	99.36
Industrial area (total SOAP = 1,653.75 µg m^{-3})	toluene	12.85	1,285.06	77.71
	ethylbenzene	2.09	233.57	14.12
	benzene	1.23	114.56	6.93
	ethanol	15.46	9.27	0.56
	propene	1.89	3.03	0.18
	total	33.53	1,645.50	99.50

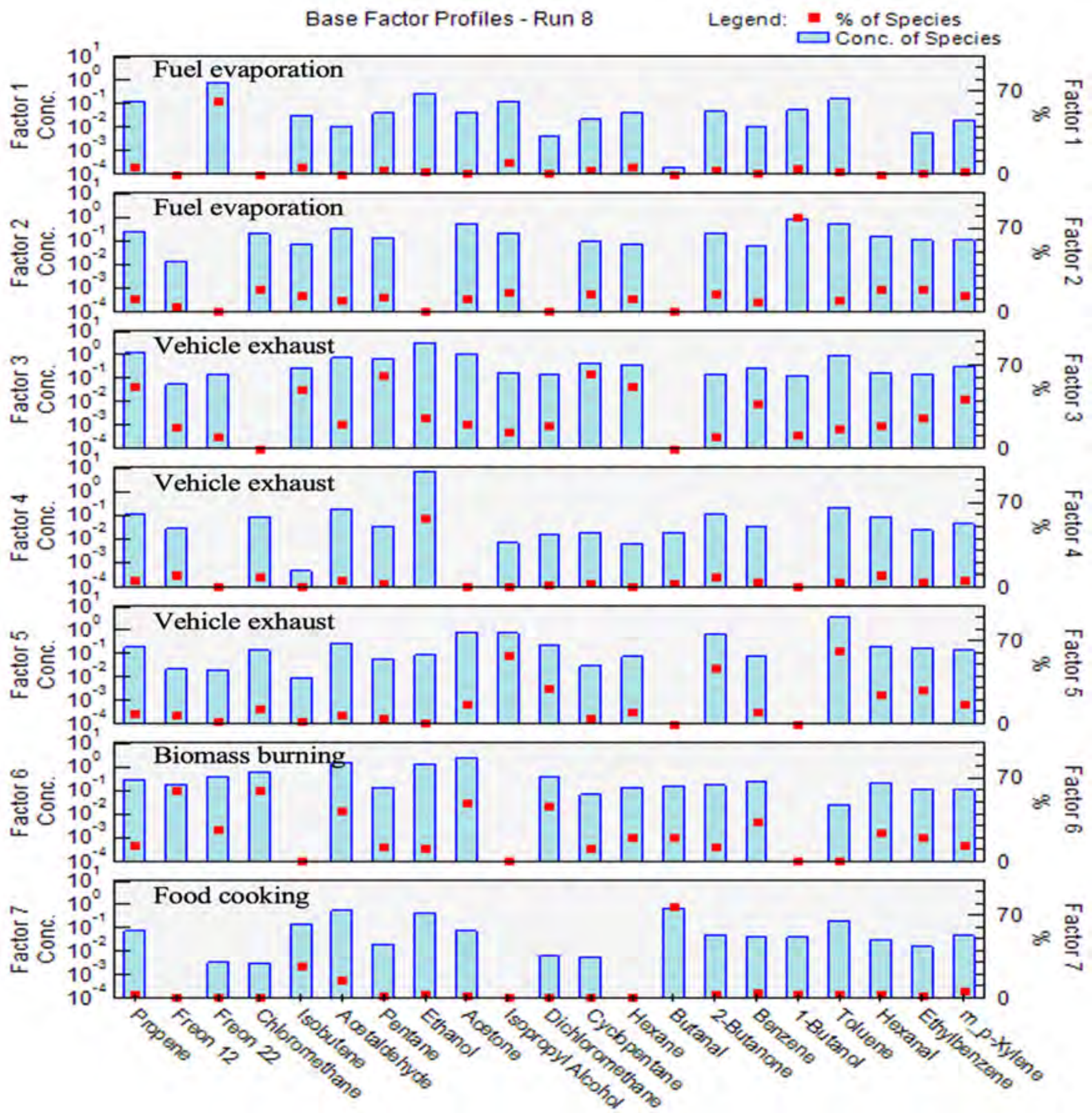

FIGURE 4 Source profiles of volatile organic compounds at all land use areas in the Bangkok Metropolitan Region, Thailand, as determined by the Positive Matrix Factorization model

were pressurized by humidified N_2 at about 20 psia to prevent contamination entering the canister. After testing, the samples were transferred to the laboratory for further chemical analysis for VOC concentration using a gas chromatograph–mass spectrophotometer.

To ensure the quality of the data, several quality assurance and quality control procedures were set in this study. At the sampling site, field blanks and duplicate samples were carried out. Field blank samples were checked to confirm that no contamination occurred from the collection, and duplicate samples were used to test the accuracy of sampling and analysis techniques (Thepanondh et al., 2011). Method detection limits (MDLs) for all the measured VOC species were determined. Their values ranged from 0.25 to 0.50 µg L^{-1}. In total, 73 VOC species were detected, including four alkanes, four alkenes, 11 aromatics, 31 halocarbons, 20 oxygenated VOCs (OVOCs), and three aldehydes (Supplemental Table S1). Completeness of the data was used as the criteria in selecting VOCs for source identification and contribution analysis. The VOC species reported as undetected with more than 25% in each VOC were excluded in this analysis.

2.3 | SOAP

Direct measurement of SOA is difficult because SOA formation is very complex and unclear. Therefore, an indirect assessment was used to calculate the SOA formation potential. The SOAP method represents the tendency for VOC species to contribute to SOA when the mass emission of that VOC

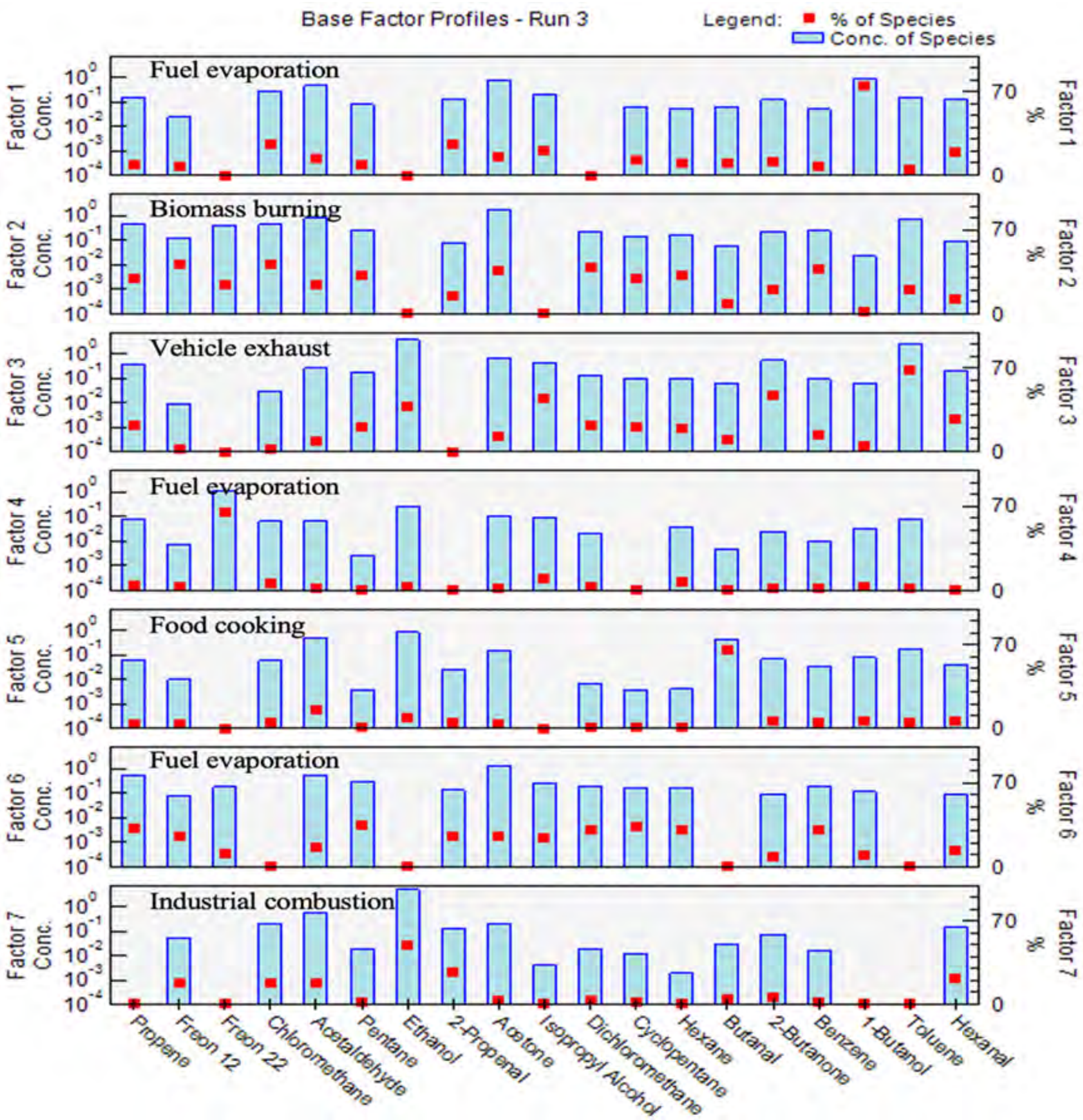

FIGURE 5 Source profiles of volatile organic compounds at general areas in the Bangkok Metropolitan Region, Thailand, as determined by the Positive Matrix Factorization model

species was added to the ambient atmosphere. In this study, the formation of SOA was calculated using measured VOC concentrations and the SOAP coefficient of individual VOC species based on the equation developed by Derwent et al. (2010). In general, SOA formation from VOCs depends on background environmental conditions tha make it difficult to quantify absolute SOA emissions (Derwent et al., 2010), and SOAP was simulated under conditions of high anthropogenic emissions of VOCs and NO_x (Derwent et al., 1998). Anthropogenic SOA plays an important role in this situation due to the low contribution from biogenic emission. Toluene was chosen as the basic compound for the SOAP because of its good emission characteristics and because it is an important man-made precursor to SOA formation (Kleindienst et al., 2007). The SOAP was estimated by multiplying the SOAP value by the median concentration of individual VOC species. Total SOAP was calculated as the sum of individual SOAP values of all the VOC species (Niu et al., 2016), as shown in Equation 1.

$$\mathrm{SOAP} = \sum C_i \times \mathrm{SOAP}_i \tag{1}$$

where C_i (μg m^{-3}) is mass concentration of species i, and SOAP_i is the SOA formation potential value of species i.

Even though SOAP was obtained by using idealized test condition, it can evaluate the relative contribution of each VOC source to the reduction of SOA. Because of the SOAP referencing SOA increments to toluene, it greatly removes issues associated with uncertainty in absolute SOA concentrations (Li et al., 2015).

2.4 | PMF modeling

The PMF model has been recommended by the USEPA as a general apportionment modeling tool. It constitutes a receptor model widely used to identify sources and their contribution of ambient PM mass concentrations and VOCs (Rai et al., 2016). The least-squares method was applied to elucidate individual chemical component error by calculating the weight and source contribution including the amount of pollution (Hui et al., 2019).

The PMF model (USEPA, ver. 5.0.14) was applied for the source contribution of VOCs in this research. The PMF model requires the use of concentration and uncertainty data for each species to analyze the source apportionment (Li et al., 2018). Measured VOC data were treated before being analyzed using the PMF. Completeness of the data was set to serve this purpose as mentioned earlier. Concentrations of VOC reported reported as undetected with more than 25% were rejected, and VOC concentrations reported as undetected with less than 25% were replaced by the MDL of each VOC. The uncertainty of VOC concentrations was calculated using the recommended USEPA Equations 2 and 3. When measured data were less than MDL, the uncertainty (Unc.) was calculated using Equation 2, and Equation 3 was used when the concentration was larger than the MDL.

$$\text{Unc.} = 5/6 \times \text{MDL} \tag{2}$$

$$\text{Unc.} = \sqrt{(\text{Error Fraction} \times \text{Concentration})^2 + (0.5 \times \text{MDL})^2} \tag{3}$$

The error fraction was set as 10% in this study.

3 | RESULTS AND DISCUSSION

3.1 | VOC concentration and composition

In this study, the composition and concentration of TVOCs classified by land use type after data treatment, presented in Supplemental Table S2, ranged from 62.67 to 126.1 μg m^{-3} (Figure 2). For all land use, the TVOC concentration was 91.51 μg m^{-3}, and the abundant groups of VOC species were the OVOCs (46.97 μg m^{-3}), aromatics (22.17 μg m^{-3}), halocarbons (12.80 μg m^{-3}), alkanes (5.83 μg m^{-3}), and alkenes (3.73 μg m^{-3},) accounting for 51.33, 24.23, 13.99, 6.37, and 4.08% of the total concentration, respectively. The TVOC concentration in general area was 74.29 μg m^{-3}, and the groups of VOC species at the highest concentration were the OVOCs (42.62 μg m^{-3}), halocarbons (11.94 μg m^{-3}), aromatics (11.25 μg m^{-3}), alkanes (5.73 μg m^{-3}), and alkenes (2.75 μg m^{-3}), accounting for 57.37, 16.07, 15.14, 7.71, and 3.71% of the total concentration, respectively. In roadside areas, the TVOC concentration was 126.1 μg m^{-3}, and the abundant groups of VOC species were the OVOCs (61.99 μg m^{-3}), aromatics (31.91 μg m^{-3}), halocarbons (15.32 μg m^{-3}), alkanes (11.71 μg m^{-3}), and alkenes (5.12 μg m^{-3}), accounting for 49.18, 25.32, 12.15, 9.29, and 4.07% of the total concentrations, respectively. The TVOC concentration in industrial areas was 62.67 μg m^{-3}, and the groups of VOC species at the highest concentration were the OVOCs (34.45 μg m^{-3}), aromatics (16.18 μg m^{-3}), halocarbons (8.86 μg m^{-3}), alkenes (1.89 μg m^{-3}), and alkanes (1.28 μg m^{-3}), accounting for 54.98, 25.82, 14.14, 3.02, and 2.05% of the total concentration, respectively. The proportions and concentrations of VOC species found in the study area were similar in each type of land use, of which the dominant component was OVOCs, accounting for 49.18–57.36% of TVOCs. Oxygenated VOCs in the atmosphere, an important fraction of the VOCs, are primarily emitted by anthropogenic emissions sources, such as vehicle emissions, solvent use, industrial activities, and biomass combustion (Han et al., 2019; Legreid et al., 2007). A comparison of VOC profiles in all land use areas with other cities is presented in Table 3. It was found that the OVOC content was higher than other studies, whereas the alkanes content was lower in this study. Li. Yin, et al. (2020) reported the characteristics of ambient VOCs measured at an urban site in central plain, China. The results showed that the group of VOC species with the highest concentration in Zhengzhou were OVOCs, accounting for 31.47% of the total, which was similar to this study where OVOCs were the abundant group of VOCs. Total VOC concentrations in all land use areas were similar to those of many cities, such as Wuhan and Seoul (Hui et al., 2018; Kang et al., 2022). Additionally, roadside area has the highest concentration (126.1 μg m^{-3}), which was higher than Beijing, where the VOC concentrations were 105.01 μg m^{-3} (Liu et al., 2020).

3.2 | Estimation of SOA formation

Formations of SOA were estimated for each sampling site (Supplemental Table S3). The total SOAP ranged from 1,134.33 to 3,143.74 μg m^{-3}. For all types of land use, the total SOA formation from VOCs was 2,188.32 μg m^{-3}, whereas the SOA formation from roadside areas was 3,143.74 μg m^{-3}, which was the highest SOAP value compared with the other areas. The SOAP in industrial area was 1,653.75 μg m^{-3}, and the lowest value in the general area was 1,134.33 μg m^{-3}. The total SOAP values of this study were similar to other studies. Q. Li et al. (2020) found that

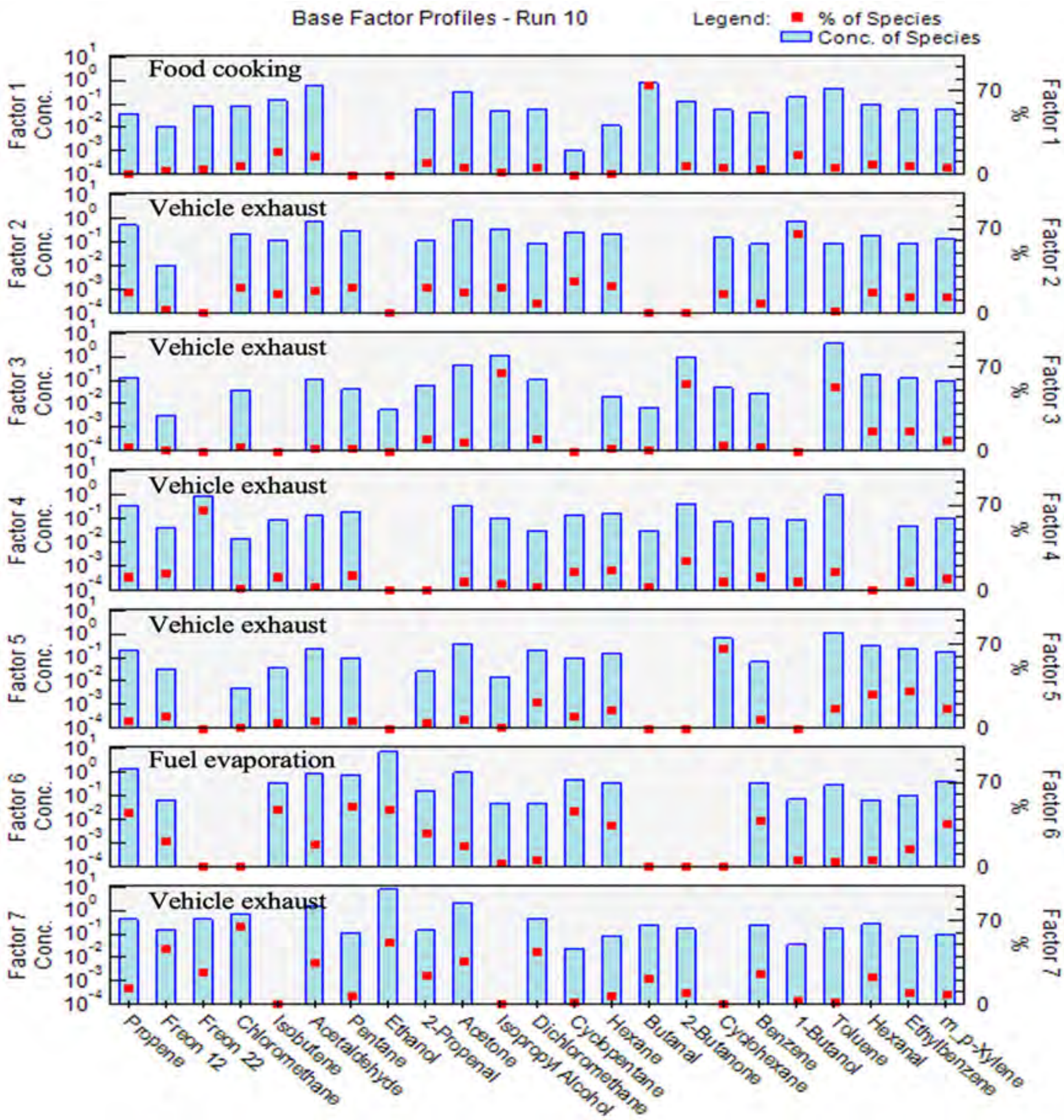

FIGURE 6 Source profiles of volatile organic compounds at roadside areas in the Bangkok Metropolitan Region, Thailand, as determined by the Positive Matrix Factorization model

the highest SOAP value during winter in Beijing, China, was 2,937.8 μg m^{-3}, and Hui et al. (2018) reported that the SOA formation on haze days in Wuhan, China, was 1,661–4,542 μg m^{-3}. Figure 3 shows that aromatics greatly contributed to the SOAP in all types of land use, accounting for about 97.80–98.81% or 1,109.37–3,106.33 μg m^{-3} of the total SOAP. This finding was similar to other studies reporting that aromatics contributed to SOA formation, accounting for 97.00–98.50% of the total SOAP (Hui et al., 2019; Zheng et al., 2021). Furthermore, studies on estimating SOA formation potential of VOCs show that aromatics are also the main contributor to atmospheric SOA formation (Chen et al., 2021) (Table 4). Hui et al. (2018) and Yang et al. (2020) elucidated the top five VOC species contributing to the SOAP in each land use. Overall results in the study areas indicated that the top five VOC species contributed more than 99% of estimated SOAP, with toluene, ethylbenzene, benzene, m,p-xylene, and ethanol accounting for 67.32, 11.80, 9.85, 9.73, and 0.56% of total SOAP, respectively. The top five VOC species for SOAP in general areas were toluene (80.05%), benzene (17.75%), ethanol (0.84%), propene (0.39%), and acetone (0.31%). In roadside areas, the top five VOC species contributing to SOA were toluene, ethylbenzene, m,p-xylene, benzene, and ethanol, accounting for 69.05, 11.30, 10.12, 8.34, and 0.55%, respectively. The top five VOC species for SOAP at industrial area were toluene (77.71%), ethylbenzene (14.12%), benzene (6.93%), ethanol (0.56%), and propene (0.18%). Toluene contributed the most to SOA formation potential throughout the observation period, accounting for 62.6–68.2% of the total SOA formation potential, followed

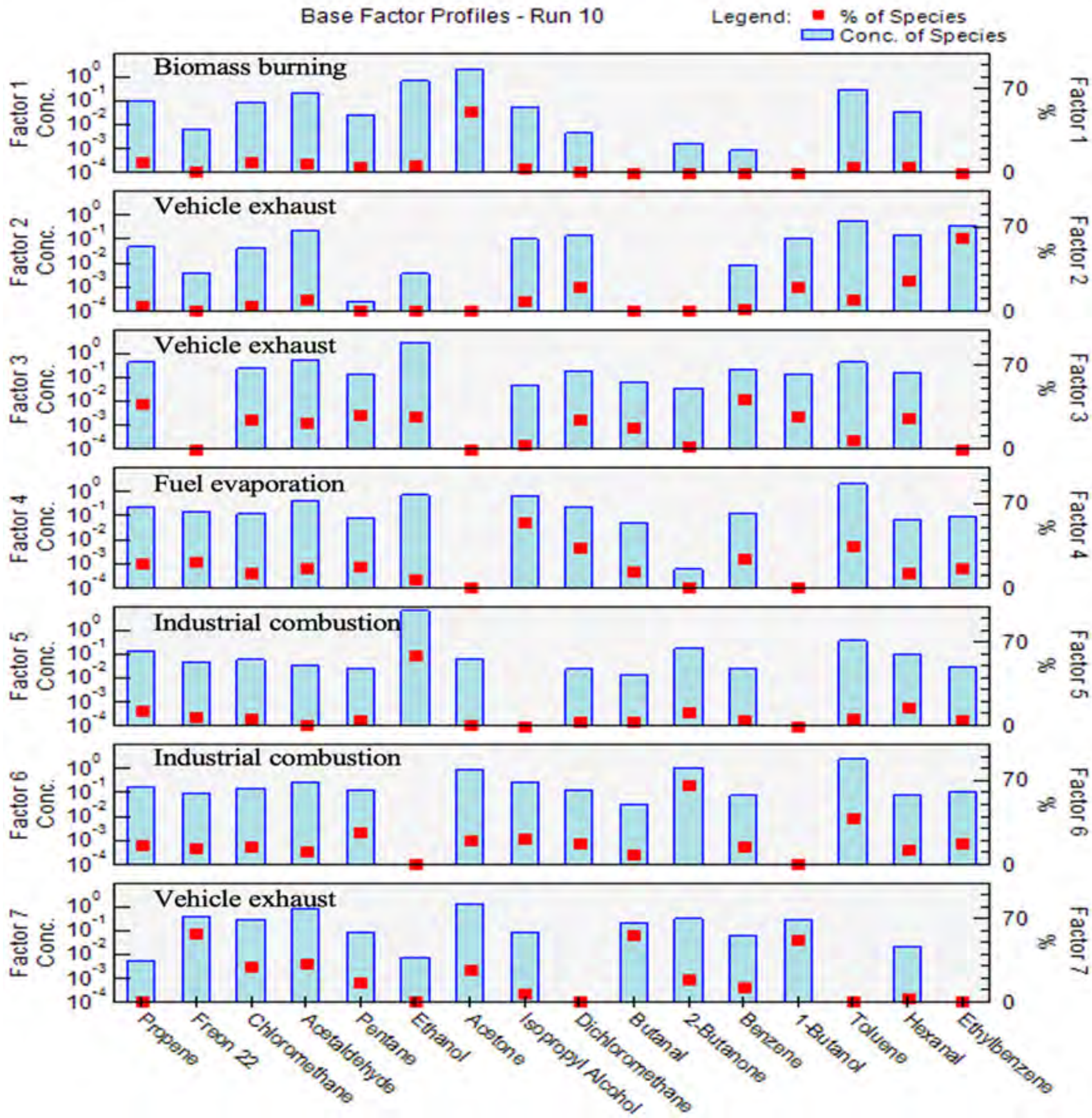

FIGURE 7 Source profiles of volatile organic compounds at industrial areas in the BMR, Thailand, as determined by the Positive Matrix Factorization model

by ethylbenzene (7.7–9.5%) and benzene (3.9–7.0%). High-molecular-weight aromatics (i.e., ethylbenzene and benzene) in photo-oxidation can transform into an aerosol phase and generate large amounts of SOA in the atmosphere (Borrás & Tortajada-Genaro, 2012; Seinfeld & Pankow, 2003). Moreover, the major role of toluene as a great contributor to SOA in this study was similar to that reported in other studies (Wu & Xie, 2018; Xiong et al., 2020).

3.3 | PMF ANALYSIS

In this investigation, the PMF model was applied to analyze the data. After data treatment, 16–23 VOC species in each land use were selected to use as input data for the model. Results of PMF analysis were explored in terms of source apportionment and source contribution of individual VOC species for SOAP.

3.3.1 | Source apportionment

The source profiles resolved factors from the PMF model in every land use type were characterized in seven factors according to signature compounds of each emission category.

Figure 4 illustrates the source profiles of overall study area. Factors 1 and 2 were identified as fuel evaporation. Factor 1 was characterized by high percentages of isopropyl alcohol and isobutene. Factor 2 contained mostly 1-butanol, hexanal, and 2-butanone. Isopropyl alcohol and isobutene are also gasoline additives (Jindamanee et al., 2020). The compound

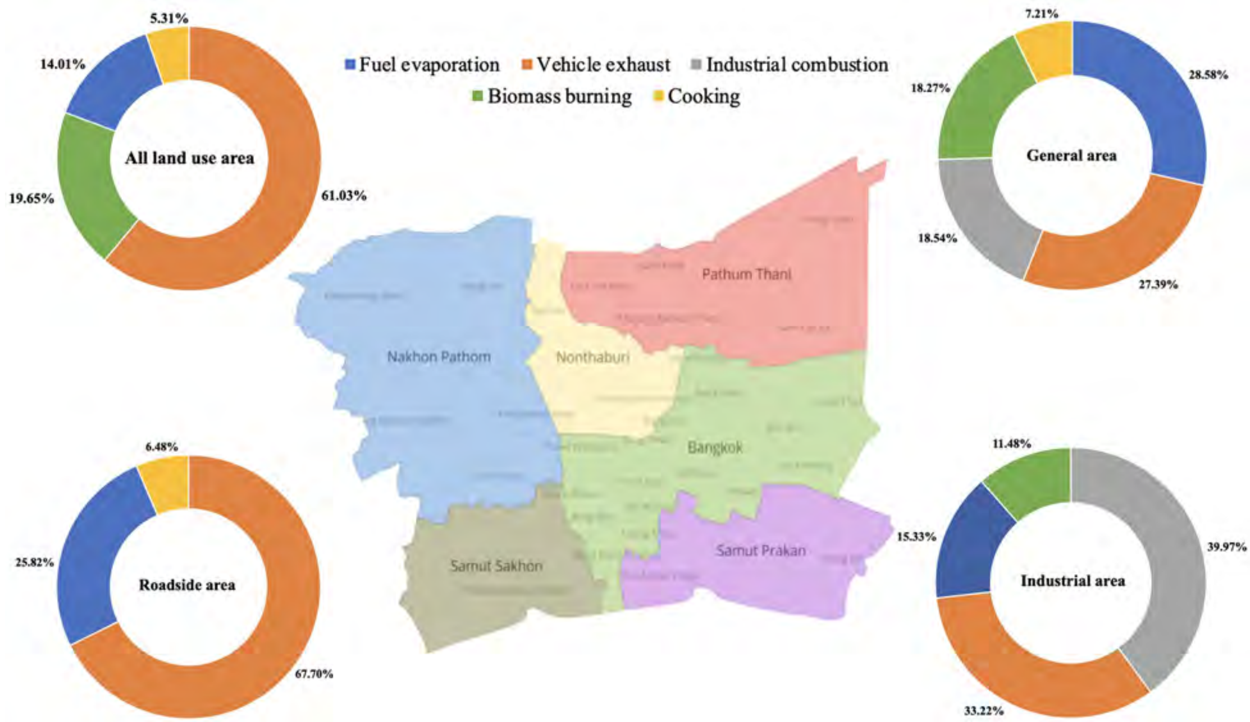

FIGURE 8 Contributions of emission sources to total volatile organic compound concentration

1-butanol is used for blending gasoline and as a diesel fuel for internal combustion engines (Altun et al., 2011). Laowagul et al. (2021) reported that hexanal and 2-butanone were abundant compounds in motorcycle lubricant. Therefore, Factors 1 and 2 were primarily attributed to fuel evaporation. Factor 3 was heavily weighted on cyclopentane, pentane, propene, and hexane. Factor 4 was mainly contributed by ethanol and hexanal. Factor 5 was characterized by high percentages of 2-butanone and BTEX (benzene, toluene, ethylbenzene, and xylenes). The exhaust of an internal combustion engine can release BTEX into the atmosphere, and 2-butanone can be produced by burning fossil fuel (Jindamanee et al., 2020; Liu et al., 2016). Propene, pentane, cyclopentane, and hexane are the most abundant compounds in gasoline exhaust (Watson et al., 2001). Ethanol is most often used as a motor fuel and is mainly used as a biofuel additive for gasoline in Thailand. In addition, hexanal was emitted at the highest levels by gasoline and diesel vehicles reported in a study by Huang et al. (2020). Therefore, Factors 3, 4, and 5 were identified as vehicle exhaust. Factor 6 was assigned as biomass burning by the high percentages of chloromethane, acetone, and dichloromethane, which were typical species from biomass burning (Scheeren et al., 2002; Singh et al., 1994; Zhang et al., 2014). Factor 7 was characterized by high percentages of butanal, isobutene, and acetaldehyde. Both butanal (the marker of wood burning) and isobutene (the major component of evaporation sources like LPG) involve the possible use of wood or LPG as fuel for cooking (Bhardwaj et al., 2021; Laowagul et al., 2021). Moreover, cooking oils showed that acetaldehyde had the highest postcooking concentrations (Seaman et al., 2009). Therefore, Factor 7 was identified as food cooking.

In general areas, Factor 1 contains a majority of 1-butanol and isopropyl alcohol, whereas Factor 4 contains isopropyl alcohol, hexane, and propene (Figure 5). Factor 6 was characterized by high percentages of propene, pentane, hexane, and cyclopentane. Hexane is the main constituent of gasoline and was reported as a tracer of gasoline evaporation in one related study (Zhang et al., 2014). Therefore, Factors 1, 4, and 6 were assigned as fuel evaporation. Factor 2 was identified as biomass burning because this factor is enriched with chloromethane. Factor 3 was considered as vehicle exhaust, characterized by the richness of toluene, 2-butanone, ethanol, and hexanal. Factor 5 was characterized by high percentages of butanal, acetaldehyde, hexanal, and 2-propenal. Acrolein (2-propenal) is produced by the incomplete combustion of organic materials like cooking oil (Seaman et al., 2009). Therefore, Factor 5 was primarily attributed to food cooking. Factor 7 was identified as industrial combustion characterized by the majority of ethanol, 2-propenal, and hexanal, which are used in industrial processes (Deleplanque et al., 2010; Šalić et al., 2013; Strohm, 2014).

The source profiles of roadside areas illustrated in Figure 6. The most abundant species in Factor 2 was 1-butanol. Dominant VOCs appeared in Factor 3, and Factor 4 comprised 2-butanone and toluene. Toluene, xylene, ethylbenzene, and

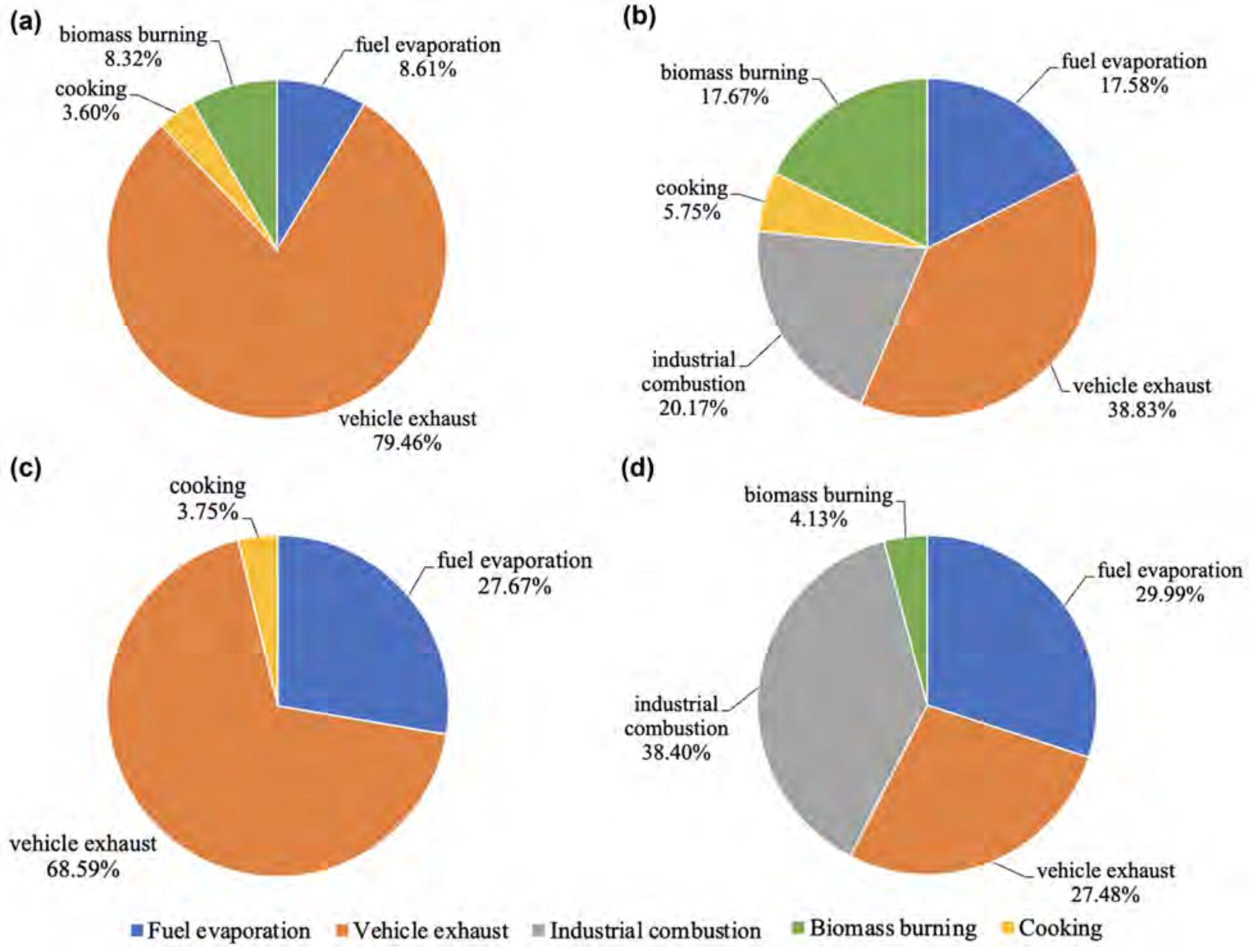

FIGURE 9 Percentage of emission sources contributing to the top five volatile organic compounds for secondary organic aerosol formation potential in (a) all land use areas, (b) general areas, (c) roadside areas, and (d) industrial areas

2-butanone are signatures of vehicle exhaust (Muezzinoglu et al., 2001; Westerholm et al., 1991). Factors 5 and 7 were mainly contributed by cyclohexane, ethylbenzene, ethanol, and dichloromethane, which were designated tracers as vehicle exhaust (Jindamanee et al., 2020). Therefore, Factors 2, 3, 4, 5, and 7 were assigned as vehicle exhaust. Factor 6 contained a majority of pentane, isobutee, propene, and cyclopentane, similar to Factor 6 in general areas. Therefore, Factor 6 was assigned as fuel evaporation. Factor 1 was characterized by high percentages of butanal, isobutene, acetaldehyde, and 2-propenal, similar to Factor 5 in general areas. Chloromethane, produced by burning charcoal as fuel for barbeque cooking (street food), was abundant in Factor 1. Therefore, Factor 1 was assigned as food cooking (barbeque).

Figure 7 shows the source profiles of industrial areas, Factor 1 contained high percentages of acetone, chloromethane, and acetaldehyde. The studies by Singh et al. (1994) and Bhardwaj et al. (2021) elucidated that acetone and acetaldehyde were related to biomass burning emissions. Factor 2 was characterized by high percentages of ethylbenzene and 1-butanol, whereas factor 3 contained high percentages of benzene, propene, and pentane. Factor 7 was characterized by high percentages of butanal and 1-butanol. Butanal and BTEX were the most abundant species emitted by vehicles (Ameur-Bouddabbous et al., 2012; Dehghani et al., 2017). Factors 2, 3, and 7 were identified as vehicle exhaust. Factor 5 contained a majority of ethanol, and Factor 6 was mainly comprised of 2-butanone and toluene, which are solvents used in manufacturing (Cheng et al., 2017). Both factors were primarily attributed to industrial combustion sources. Factor 4 was identified as fuel evaporation because this factor was enriched with isopropyl alcohol, propene, and pentane.

Contributions of each emission source to TVOC concentration (summarized in Figure 8) are calculated from the total VOC concentrations in each factor analyzed by the PMF model. After that, all VOC concentrations of each factor identified as the same source are merged and account for the proportion of each source compared with the total concentration from all sources in the area. Vehicle exhaust and fuel evaporation were the major emission sources contributing to TVOC concentrations in all types of study areas. Vehicle exhaust emission is a predominant source in roadside and

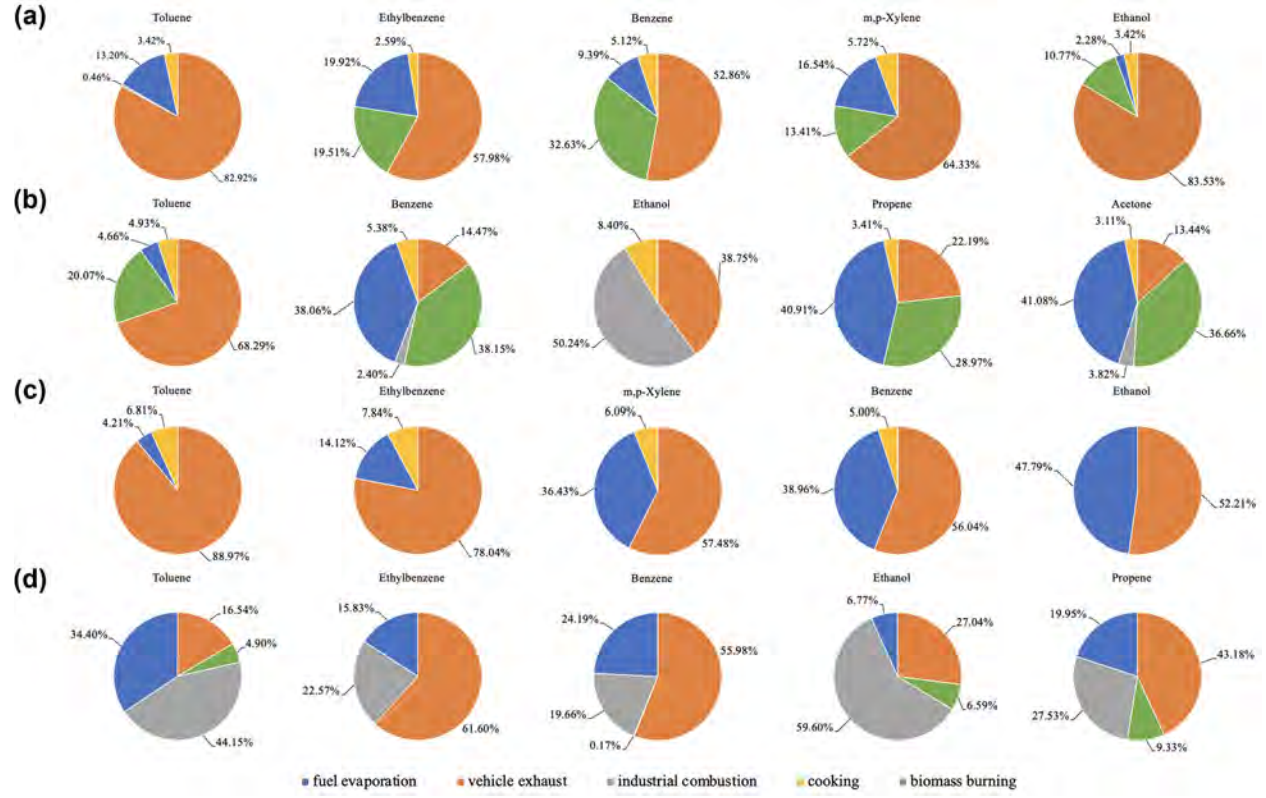

FIGURE 10 Source contribution of the top five volatile organic compound species contributing to secondary organic aerosol formation potential in (a) all land use areas, (b) general areas, (c) roadside areas, and (d) industrial areas

overall areas, accounting for 67.70 and 61.03%, respectively, followed by industrial (33.22%) and general areas (27.39%). Evaporation of fuel is a main emission source, contributing 28.58% of TVOC concentrations in general (residential) areas, and the sources of fuel evaporation in roadside, industrial, and all land use areas account for 25.82, 15.33, and 14.01%, respectively. Biomass combustion was found in three areas; the largest percentage of biomass combustion was found in all land use areas, accounting for 19.65%, followed by general (18.27%) and industrial areas (11.48%). On the other hand, biomass burning sources did not contribute VOCs to roadside areas. There were three areas where food cooking was one of the VOC emission sources; general areas have 7.21% of cooking sources, which is a higher proportion than other areas. Roadsides and all types of areas account for 6.48 and 5.31% of VOC emissions, respectively. Additionally, industrial combustion emissions were found in general areas (18.54%), and the main source contributing to TVOC concentrations in industrial areas were industrial combustion sources (accounting for 39.97%).

Ma et al. (2019) studied the sources of VOCs identified by the PMF model based on the measurement data in Shenyang, a typical urban area of Northeast China. They found that vehicle exhaust contributed the most TVOCs, accounting for 36.15%. Wang et al. (2016) reported that vehicle exhaust emission was the main VOC contributor in the suburban area of Beijing, China, with a contribution of 38.5–44.2%. Wang, Zhang, et al. (2018) repoted that vehicle emissions were the major VOC sources in Wuhan, China, contributing 45.4% of the measured VOC concentrations. Moreover, Yu et al. (2014) reported that the dominant VOC source to ambient air in New Jersey, USA, was vehicle exhaust (20.3%). According to the studies mentioned above, vehicle exhaust was the most prominent source of exhaust in each city, similar to the findings in this study, in which the major emission sources contributing to TVOC concentrations in overall areas of the BMR and roadside areas were vehicle exhaust sources (>60%).

3.3.2 | Source identification of the top five VOC species contributing to SOAP

This section presents the source contribution of the top five VOCs species contributing to SOAP. As illustrated in Figure 9, vehicle exhaust comprised the major source of VOCs contributing to SOA in all land use areas, roadside areas, and general areas in the BMR, accounting for 79.46, 68.5, and 38.83%, respectively. However, in the industrial area, industrial combustion sources were the major contributors.

TABLE 5 Comparison of volatile organic compounds (VOCs) contributing to secondary organic aerosol (SOA) and secondary organic aerosol formation potential (SOAP) among studies

Location	Area	Major emission source contributing to SOAP	Source contribution of VOCs contributing to SOAP	Top VOC species contributing to SOA	Reference
			%		
Bangkok and vicinity, Thailand	all areas	vehicle exhaust	79.46	toluene	this study
	general area	vehicle exhaust	38.83	toluene	this study
	roadside area	vehicle exhaust	68.59	toluene	this study
	industrial area	industrial combustion	38.40	toluene	this study
Calgary, Canada	urban	traffic emissions	47.00	toluene	Xiong et al. (2020)
Central China	urban	industrial sources	32.80		Zheng et al. (2021)
Beijing, Tianjin, Hebei, China	urban	petrochemical industries	24.90	toluene	Wu and Xie (2018)
Shandong, Hebei, Shanxi, Neimeng, and Xinjiang, China	urban	industrial process	42.20–69.50		Wu et al. (2017)
Pearl River Delta, China	urban	surface coating	24.20	toluene	Wu and Xie (2018)
Shanghai, China	urban	vehicle exhaust	24.30		Wang et al. (2013)
Sichuan, Chongqing, China	urban	on-road vehicles	25.20	toluene	Wu and Xie (2018)
Wuhan, China	urban	solvent use	20.86	toluene	Hui et al. (2019)
Yangtze River Delta, China	urban	petrochemical industries	38.60	toluene	Wu and Xie (2018)
United Kingdom	urban	road transport	45.00	toluene	Derwent et al. (2010)
San Joaquin Valley, CA, USA	rural	solvent use	28.00		Chen et al. (2010)

Figure 10 illustrates that the source profile of each of the top five VOC species contributed to SOA formation. For all land use areas, the top five VOC species were toluene, ethylbenzene, benzene, m,p-xylene, and ethanol. Vehicle exhaust was the major source of emissions for all of top five species, representing 52.86–83.53%. In general areas, toluene, benzene, ethanol, propene, and acetone were the top five VOC species. Fuel evaporation was the main emission source contributing to benzene, propene, and acetone, accounting for 38.06–41.08%. Toluene was primarily emitted from vehicle exhaust sources (68.29%), ethanol was primarily emitted from industrial combustion processes (50.24%). The top five VOC species contributing to SOA formation in roadside areas were similar to the top 5 VOC species of all land use areas. Vehicle emissions were the prominent source contribution of all top five species, representing 52.21–88.97%. Additionally, toluene, ethylbenzene, benzene, ethanol, and propene were the top five VOC species in industrial areas. Vehicle exhaust was the major source ethylbenzene, benzene, and propene, accounting for 43.18–61.60%. Toluene and ethanol were primarily emitted from industrial combustion sources (44.15–59.60%). From these findings, toluene, which was considered the most important SOA contributor in this study, was the predominant source of VOC species contributing to SOA in all land use types in BMR; this finding is similar to other studies, indicating that toluene is the primary VOC species contributing to SOA in many cities, such as in the United Kingdom and in Wuhan, and Calgary (Derwent et al., 2010; Hui et al., 2019; Xiong et al., 2020).

The findings in this study, compared with other related research, are summarized in Table 5. Xiong et al. (2020) studied source contributions to VOCs contributing to SOA in downtown Calgary, Alberta, Canada, for the period of 2013–2017 and found that traffic-related emissions were the dominant VOC sources contributing to SOA formation in Calgary, representing 47%. Derwent et al. (2010) reported that road transport in the United Kingdom contribute 45% of the SOAP-weighted man-made mass emissions in the year 2000.

In addition, vehicle exhaust was the most important contributor to SOA in Shanghai (24.30%), Sichuan, and Chongqing, China (25.20%) (Wang et al., 2013; Wu & Xie, 2018). Vehicle exhaust was the major source of VOCs contributing to the most SOA in all land use and roadside areas, accounting for 79.46 and 68.59%, respectively. Compared with the other cities mentioned above, it was found that the dominant VOC sources contributing to SOA formation in this study was higher than in other cities. According to CNN Money, the 2017 ranking of cities with the most severe evening rush hour traffic show that Bangkok has the worst traffic in the world (Petroff, 2017). These ranking data are consistent with this study showing that BMR has more vehicle exhaust emission sources contributing to SOAP than any other country.

4 | CONCLUSION

An intensive study of formation potential and source contribution of SOA from VOCs was conducted in the BMR, Thailand. Ambient VOC concentrations, obtained from direct measurement, were comprehensively evaluated to identify the abundant VOC species and emission sources of VOCs contributing to SOA as well as the contribution of each emission source using the PMF model. Analytical results revealed that the largest group of VOC concentrations found overall in the BMR including all land use areas, general areas, roadside areas, and industrial areas constituted the OVOCs, accounting for 49.18–57.36% of total VOCs. On the other hand, aromatics were a major group of VOCs contributing to SOA, accounting for 97.80–98.81%. Among them, toluene was the most abundant SOA contributor, accounting for over 65% of total SOAP. Results from the source apportionment analysis elucidated that more than 60% of TVOC concentrations in all land use areas and roadside areas were contributed from vehicle exhaust sources, whereas fuel evaporation was the main source of VOC emissions in the general area, accounting for 28.58%. Further, about 39.97% of total VOC concentration in industrial areas was from industrial combustion sources. Results of source contribution of the top five VOCs species contributing to the largest SOA indicated that vehicle exhaust was the major source of VOCs contributing to the most SOA overall in the BMR. Findings of this study revealed that efforts to control emissions from mobile sources (both from the combustion and evaporation of fuel) should be given the highest priority. Street food, biomass burning, and industrial combustion also contribute to the emissions of SOA precursors in the BMR. Results and methods from this intensive study revealed the necessity to identify the sources of major VOCs contributing to the formation of SOA, which should also be applied in other regions where fine particulate matter is a concerning emerging air pollutant.

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AUTHOR CONTRIBUTIONS

Peemapat Jookjantra: Formal analysis. sarawut thepanondh: Validation; Writing – review & editing. Jutarat Keawboonchu: Investigation. Vanitchaya Kultan: Data curation; Investigation. Wanna Laowagul: Investigation.

CONFLICT OF INTEREST

The authors declare no conflict of interest.

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SUPPORTING INFORMATION

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Abandoned wells can be 'super-emitters' of greenhouse gas

By John Sullivan, Office of Engineering Communications on Dec. 9, 2014, 11:15 a.m.

Princeton University researchers have uncovered a previously unknown, and possibly substantial, source of the greenhouse gas methane to the Earth's atmosphere.

After testing a sample of abandoned oil and natural gas wells in northwestern Pennsylvania, the researchers found that many of the old wells leaked substantial quantities of methane. Because there are so many abandoned wells nationwide (a recent study from Stanford University concluded there were roughly 3 million abandoned wells in the United States) the researchers believe the overall contribution of leaking wells could be significant.

Alana Miller (left), a Princeton senior majoring in civil and environmental engineering, and Mary Kang, then a doctoral researcher in civil and environmental engineering at Princeton, conduct research that found abandoned oil and gas wells emit methane, a powerful greenhouse gas. Kang, now at Stanford University, is the lead author of a recent journal article describing the findings. *(Photo courtesy of Robert Jackson, Stanford University)*

The researchers said their findings identify a need to make measurements across a wide variety of regions in Pennsylvania but also in other states with a long history of oil and gas development such as California and Texas.

"The research indicates that this is a source of methane that should not be ignored," said **Michael Celia** (http://www.princeton.edu/cee/people/display_person/?netid=celia), the Theodore Shelton Pitney Professor of Environmental Studies and professor of **civil and environmental engineering** (http://www.princeton.edu/cee/) at Princeton. "We need to determine how significant it is on a wider basis."

Methane is the unprocessed form of natural gas. Scientists say that after carbon dioxide, methane is the most important contributor to the greenhouse effect, in which gases in the atmosphere trap heat that would otherwise radiate from the Earth. Pound for pound, methane has about 20 times the heat-trapping effect as carbon dioxide. Methane is produced naturally, by processes including decomposition, and by human activity such as landfills and oil and gas production.

While oil and gas companies work to minimize the amount of methane emitted by their operations, almost no attention has been paid to wells that were drilled decades ago. These wells, some of which date back to the 19th century, are typically abandoned and not recorded on official records.

Mary Kang, then a doctoral candidate in civil and environmental engineering at Princeton, originally began looking into methane emissions from old wells after researching techniques to store carbon dioxide by injecting it deep underground. While examining ways that carbon dioxide could escape underground storage, Kang wondered about the effect of old wells on methane emissions.

“I was looking for data, but it didn’t exist,” said Kang, now a postdoctoral researcher at Stanford.

In a **paper** (http://www.pnas.org/content/early/2014/12/04/1408315111.full.pdf+html) published Dec. 8 in the Proceedings of the National Academy of Sciences, the researchers describe how they chose 19 wells in the adjacent McKean and Potter counties in northwestern Pennsylvania. The wells chosen were all abandoned, and records about the origin of the wells and their conditions did not exist. Only one of the wells was on the state’s list of abandoned wells. Some of the wells, which can look like a pipe emerging from the ground, are located in forests and others in people’s yards. Kang said the lack of documentation made it hard to tell when the wells were originally drilled or whether any attempt had been made to plug them.

“What surprised me was that every well we measured had some methane coming out,” said Celia.

A well pipe emerges from the ground in the Allegheny National Forest in northwestern Pennsylvania. Researchers covered pipes from 19 wells with instruments to measuring gases emitted by the well. *(Photo courtesy of Mary Kang, Department of Civil and Environmental Engineering)*

To conduct the research, the team placed enclosures called flux chambers over the tops of the wells. They also placed flux chambers nearby to measure the background emissions from the terrain and make sure the methane was emitted from the wells and not the surrounding area.

Although all the wells registered some level of methane, about 15 percent emitted the gas at a markedly higher level — thousands of times greater than the lower-level wells. **Denise Mauzerall** (http://www.princeton.edu/cee/people/display_person/?netid=mauzeral), a Princeton professor and a member of the research team, said a critical task is to discover the characteristics of these super-emitting wells.

Mauzerall said the relatively low number of high-emitting wells could offer a workable solution: while trying to plug every abandoned well in the country might be too costly to be realistic, dealing with the smaller number of high emitters could be possible.

"The fact that most of the methane is coming out of a small number of wells should make it easier to address if we can identify the high-emitting wells," said Mauzerall, who has a joint appointment as a professor of civil and environmental engineering and as a professor of public and international affairs at the **Woodrow Wilson School** (http://wws.princeton.edu/).

The researchers have used their results to extrapolate total methane emissions from abandoned wells in Pennsylvania, although they stress that the results are preliminary because of the relatively small sample. But based on that data, they estimate that emissions from abandoned wells represents as much as 10 percent of methane from human activities in Pennsylvania — about the same amount as caused by current oil and gas production. Also, unlike working wells, which have productive lifetimes of 10 to 15 years, abandoned wells can continue to leak methane for decades.

"This may be a significant source," Mauzerall said. "There is no single silver bullet but if it turns out that we can cap or capture the methane coming off these really big emitters, that would make a substantial difference."

Besides Kang, who is the paper's lead author, Celia and Mauzerall, the paper's co-authors include: Tullis Onstott, a professor of geosciences at Princeton; Cynthia Kanno, who was a Princeton undergraduate and who is a graduate student at the Colorado School of Mines; Matthew Reid, who was a graduate student at Princeton and is a postdoctoral researcher at EPFL in Lausanne, Switzerland; Xin Zhang, a postdoctoral researcher in the Woodrow Wilson School at Princeton; and Yuheng Chen, an associate research scholar in geosciences at Princeton.

Support for the research was provided in part by the **Princeton Environmental Institute** (http://www.princeton.edu/pei/), the **National Oceanic and Atmospheric Administration** (http://www.noaa.gov/wx.html), the **National Sciences and Engineering Research Council of Canada** (http://www.nserc-crsng.gc.ca/), and the **Yale Center for Environmental Law and Policy** (http://envirocenter.yale.edu/).

Identification and characterization of high methane-emitting abandoned oil and gas wells

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Recent measurements of methane emissions from abandoned oil/gas wells show that these wells can be a substantial source of methane to the atmosphere, particularly from a small proportion of high-emitting wells. However, identifying high emitters remains a challenge. We couple 163 well measurements of methane flow rates; ethane, propane, and *n*-butane concentrations; isotopes of methane; and noble gas concentrations from 88 wells in Pennsylvania with synthesized data from historical documents, field investigations, and state databases. Using our databases, we (*i*) improve estimates of the number of abandoned wells in Pennsylvania; (*ii*) characterize key attributes that accompany high emitters, including depth, type, plugging status, and coal area designation; and (*iii*) estimate attribute-specific and overall methane emissions from abandoned wells. High emitters are best predicted as unplugged gas wells and plugged/vented gas wells in coal areas and appear to be unrelated to the presence of underground natural gas storage areas or unconventional oil/gas production. Repeat measurements over 2 years show that flow rates of high emitters are sustained through time. Our attribute-based methane emission data and our comprehensive estimate of 470,000–750,000 abandoned wells in Pennsylvania result in estimated state-wide emissions of 0.04–0.07 Mt (10^{12} g) CH_4 per year. This estimate represents 5–8% of annual anthropogenic methane emissions in Pennsylvania. Our methodology combining new field measurements with data mining of previously unavailable well attributes and numbers of wells can be used to improve methane emission estimates and prioritize cost-effective mitigation strategies for Pennsylvania and beyond.

abandoned wells | oil and gas development | methane emissions | high emitters | climate change

Methane is a potent greenhouse gas (GHG) with a global warming potential 86 times greater than carbon dioxide over a 20-y time horizon (1). A reduction of methane emissions can lead to substantial climate benefits, especially in the short term (2). Recent measurements of methane emissions from abandoned oil and gas wells in Pennsylvania indicate that these wells may be a significant source of methane to the atmosphere (3). Across the United States, the number of abandoned oil/gas wells is estimated to be 3 million or more (4, 5), and this number will continue to increase in the future. As of February of 2016, abandoned oil/gas wells remain outside of GHG emissions inventories, despite evidence that emissions may be substantial nationally. As interest in mitigation of GHG emissions increases, quantifying persistent and large emissions and mitigating them will be increasingly important.

Methane emissions from abandoned wells, as with other fugitive sources in the oil and gas sector, appear to be governed by relatively few high emitters (3, 6–8). It is important for current and future abandoned wells to identify the characteristics that lead to high emissions. This information can provide a rationale for prioritized mitigation.

The century-and-a-half-long history of oil and gas development in Pennsylvania and other US states, such as Texas and California, has resulted in millions of abandoned wells, and in many cases, poorly documented or missing well records (3, 9–11). As a result, there is a lack of data to characterize abandoned oil and gas wells and the possible relationship between methane emissions and well attributes. Well attributes that may be correlated with methane emissions include depth, plugging status, well type, age, wellbore deviation, geographic location, oil/gas production, and abandonment method (9, 10, 12–14). Previous studies have been limited to wells and attributes with readily available data (12, 14). However, compilation and analysis of historical documents, modern digital databases, and field investigations can be used to infer well attributes of the many wells without data. In this work, we focus on Pennsylvania, which has the longest history of oil and gas development, to determine and explore the role of well attributes, mainly depth, plugging status, well type (e.g., gas or oil), and coal area designation as well as proximity to subsurface-based energy activities, on methane leakage.

Previously estimated numbers of abandoned wells in Pennsylvania range from 300,000 to 500,000 (3, 15) and are based on either incomplete databases or qualitative expert opinion. The Pennsylvania Department of Environmental Protection (DEP) manages oil and gas well data and has records of only 31,676 abandoned oil and gas wells for the state as of October of 2015. Only 5% of the wells in Pennsylvania measured in an earlier study (3) were on the DEP's list. Furthermore, because of changes in governing bodies and regulations over time, the quality of available records is likely to be poorer for older wells (15). To estimate the actual number of wells,

Significance

Millions of abandoned oil and gas wells exist across the United States and around the world. Our study analyzes historical and new field datasets to quantify the number of abandoned wells in Pennsylvania, individual and cumulative methane emissions, and the attributes that help explain these emissions. We show that (*i*) methane emissions from abandoned wells persist over multiple years and likely decades, (*ii*) high emitters appear to be unplugged gas wells and plugged/vented gas wells, as required in coal areas, and (*iii*) the number of abandoned wells may be as high as 750,000 in Pennsylvania alone. Knowing the attributes of high emitters will lead to cost-effective mitigation strategies that target high methane-emitting wells.

Author contributions: M.K. designed research; M.K., S.C., M.A.C., D.L.M., M.B., A.R.M., Y.C., M.E.C., T.H.D., and R.B.J. performed research; M.K., S.C., M.B., and T.H.D. contributed new reagents/analytic tools; M.K., S.C., M.B., A.R.M., Y.C., and T.H.D. analyzed data; and M.K., S.C., M.A.C., D.L.M., M.B., Y.C., M.E.C., T.H.D., and R.B.J. wrote the paper.

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historical documents and other data sources from oil and gas development need to supplement state records.

Pennsylvania, Ohio, West Virginia, and Kentucky, states through which the Appalachian Basin extends, are among the top 10 US states in terms of the number of inactive and total oil and gas wells (10). Questions remain about potential links between abandoned wells and other active subsurface-based energy activities commonly found in theses states, such as, underground natural gas storage and unconventional oil/gas production (9, 16). For example, could nearby unconventional gas production or underground gas storage reservoirs lead to larger methane leaks from abandoned wells? Previously available measurements and data are insufficient to explore these potential effects. Therefore, we conducted additional field measurement campaigns to fill the data gaps. In the process, we expanded the geographic coverage, previously limited to northwestern Pennsylvania (3), to cover much of the western portion of the state (Fig. 1).

Geochemical information including methane and noble gas isotopes is useful for understanding methane sources (16–18). To evaluate wellbore integrity and design effective mitigation strategies, it is important to identify the source of methane, including whether it is microbial or thermogenic, and if possible, the source formation and migration pathway. It is also important to know as many well attributes as possible and cross-check those attributes with geochemical data when possible. Here, we provide an expanded set of geochemical information including carbon and hydrogen isotopes of methane and concentrations of ethane, propane, *n*-butane, and noble gases.

To identify and characterize high methane-emitting abandoned oil/gas wells, we provide in this paper (*i*) a database of previously unavailable attributes of measured abandoned wells; (*ii*) 122 additional field measurements over multiple seasons of methane flow rates and geochemical data, including previously unavailable hydrogen isotopes of methane and noble gas data; (*iii*) improved estimates of well numbers based on all available data sources; and (*iv*) an attribute-based methane emissions estimate for abandoned oil and gas wells in Pennsylvania. These data and the associated analysis framework will improve estimates of methane emissions from abandoned oil and gas wells and help develop mitigation strategies across Pennsylvania and beyond.

Results

Methane Flow Rates and Well Attributes. Methane flow rates span from below detection (BD) to 10^5 mg h^{-1} $well^{-1}$ for positive methane flow rates (sources of methane to the atmosphere) and from BD to -10^1 mg h^{-1} $well^{-1}$ for negative methane flow rates (sinks of methane from the atmosphere) (Fig. 2). Most methane flow rates from abandoned wells (90%) are positive, and all negative numbers are small in magnitude.

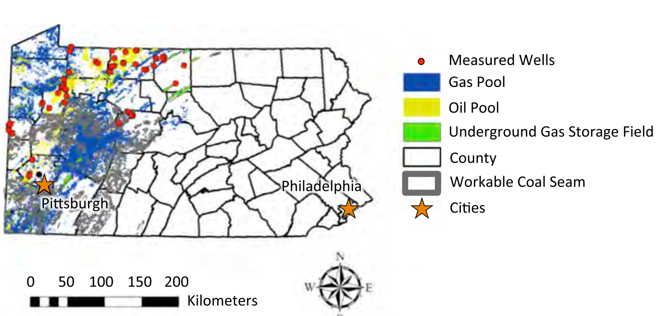

Fig. 1. The 88 measured abandoned oil and gas wells in Pennsylvania overlaid with conventional oil and gas pools (34), underground natural gas storage fields (34), and workable coal seams within the study area (38).

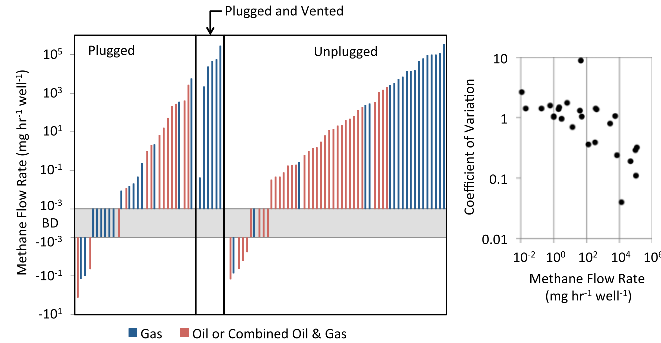

Fig. 2. Methane flow rates of 88 abandoned wells in Pennsylvania and the coefficient of variation of methane flow rates measured from 2 to 10 times over 2 years (July of 2013 to June of 2015) at 27 wells. If more than one measurement has been made at the given well, the methane flow rates represent an average of all measurements taken. Plugging status is determined based on field observations, and the well type (gas vs. oil or combined oil and gas) is determined using our database-based estimates of well attributes. Methane flow rates below detection (BD) limits (P values > 0.2) are shown in the gray portion of the plot between the plots of positive and negative flow rates.

Methane flow rates are measured from different categories of abandoned wells in Pennsylvania. For the measured wells without well records, plugging status is determined based on field observations, and the well type (gas vs. oil or combined oil and gas) is determined based on our estimates of well attributes from our assembled database (*SI Appendix*). Across the dataset, abandoned gas wells, specifically unplugged and plugged/vented wells (Pennsylvania Code, Chapter 78), have the highest observed rates of methane emissions (Fig. 2). Abandoned oil wells have consistently lower emissions compared with abandoned gas wells (Fig. 2). The highest measured methane flow rate is 3.5×10^5 mg h^{-1} $well^{-1}$ at an unplugged gas well in McKean County, and the second highest is 2.9×10^5 mg h^{-1} $well^{-1}$ at a plugged but vented gas well in Clearfield County. Venting of plugged wells is required in coal areas, which in Pennsylvania, include regions where mineable coal seams exist (*SI Appendix*).

Methane flow rates are most strongly related to well type (W; gas vs. oil or combined oil and gas), plugging status (P), and coal area designation (C) (Table 1 and *SI Appendix*, Table S3). No strong trends are observed between methane flow rates and well depth (d), distance to the nearest unconventional well (r_U), or distance to the nearest underground natural gas storage field (r_S). A multilinear fit of d, W, P, C, r_U, and r_S to ln $\dot{m}$, where $\dot{m}$ (mg $hour^{-1}$ $well^{-1}$) is the methane flow rate, gives an R^2 value of 0.44 and a P value of 4.4×10^{-8}. The P values for the intercept, C, P, and W are below 0.05 and range from 2×10^{-6} (for C) to 0.04 (for the intercept). The P values for d, r_S, and r_U are high at 0.3, 0.8, and 0.4, respectively. The statistically significant well attributes (P values < 0.05) based on the multilinear regression analysis (Table 1 and *SI Appendix*, Table S3) are used in methane emissions estimation. The methane emission factors for nine well categories defined by combinations of W, P, and C range from 1.2×10^{-2} to 6.0×10^4 mg h^{-1} $well^{-1}$ (Table 2).

Methane Flow Rates over Time. Repeat measurements of the same abandoned wells conducted 2–10 times (July of 2013 to June of 2015) (*SI Appendix*, Table S2) show that high emitters ($\geq 10^4$ mg h^{-1} $well^{-1}$) have relatively low coefficients of variation, with values ranging from 0.04 to 0.3 (Fig. 2). This result implies that high emitters are emitting methane at consistent levels over multiple years. The coefficient of variation decreases with increasing methane flow rates, implying that lower emitters are more likely to be influenced by variable factors, such as seasonal impacts and measurement error. We also find that the coefficient of variation is

Table 1. Variable coefficients of the multilinear model with R^2 value of 0.44 and P value of 4.4×10^{-8}

Variable in model	Variable coefficient
Intercept	2.84*
D	0.00039
C = coal area	−5.50***
P = unplugged	3.99***
P = plugged/vented	8.33***
W = oil	−2.88*
r_S	0.016
r_U	−0.087

These results are for model L6b in *SI Appendix*, Table S3. The results of additional models are shown and discussed in *SI Appendix*. P values are noted (*$P < 0.05$; ***$P < 0.001$).

unrelated to the number of repeat measurements (*SI Appendix*, Fig. S2).

Geochemistry. The origin of methane from high-emitting wells is predominantly thermogenic, with $\delta^{13}C\text{-}CH_4$ values ranging from −33 to −45‰ (Fig. 3). [Thermogenic methane typically has $\delta^{13}C\text{-}CH_4$ values greater than ∼−40 to −50‰, whereas microbial methane typically has $\delta^{13}C\text{-}CH_4$ values below −50‰ (17, 19, 20); intermediate $\delta^{13}C\text{-}CH_4$ values, around −50‰, can represent mixed thermogenic and microbial sources.] The ratio of C_{2-4}/C_1 confirms the thermogenic source of high emitters, because the ratio ranges from 0.01 to 0.2. [Microbial sources of methane typically have ratios less than 0.0005 (19, 21).] A larger range in both $\delta^{13}C\text{-}CH_4$ and C_{2-4}/C_1 values is observed for oil compared with gas wells, with oil wells more likely to emit methane in the microbial range. We do not observe a strong difference in methane isotopes or hydrocarbon ratios between plugged and unplugged wells, although we find that plugged/vented wells have narrower ranges in $\delta^{13}C\text{-}CH_4$ and C_{2-4}/C_1 values. Wells in coal areas tend to have lower C_{2-4}/C_1 ratios, regardless of their plugging status or well type, with ratios ranging from 0.001 to 0.04. For wells (in any area) where both $\delta^{13}C\text{-}CH_4$ and $\delta^{2}H\text{-}CH_4$ are analyzed, most are found to be within the thermogenic range for gases associated with oil reservoirs (17).

High methane-emitting gas wells are found to have the following noble gas ratios: $^3He/^4He < 0.10R_A$ (where R/R_A is the ratio of ^3He to ^4He in a sample compared with the ratio of those isotopes in air, and R_A nomenclature denotes the $^3He/^4He$ ratios of samples with respect to air), $^4He/^{22}Ne > 100$, and $CH_4/^{36}Ar > 1{,}000$ (Fig. 3 and *SI Appendix*, Fig. S4). ^4He occurs in very low abundances in the atmosphere and is not produced in association with biogenic methane (22). By comparison, ^{22}Ne and ^{36}Ar are ubiquitous, well-mixed, and uniform in the atmosphere. As a result, the noble gases and specifically, elevated levels of ^4He or ratios of thermogenic gases (^4He or CH_4) to atmospheric gases are able to identify high thermogenic methane-emitting gas wells, which cannot always be achieved with hydrocarbon-based geochemical information alone (23).

Number of Abandoned Wells. Using comprehensive databases (15, 24) and analysis of historical documents (25–28) (*SI Appendix*), we estimate the number of abandoned wells in Pennsylvania to be between 470,000 and 750,000 (*SI Appendix*, Table S4). The key difference between our well numbers and previous lower estimates is that we include additional wells drilled for enhanced recovery (ER) purposes (*SI Appendix*). Similar to oil and gas wells used for production, injection wells drilled for water flooding, a widely used enhanced oil recovery technique (26, 29), can also act as pathways for methane and other fluid migration. The data show that the inclusion of ER wells leads to an increase in estimated well numbers by multiplicative factors of 1.7–3.5. We base our estimate of ER wells using these factors for years before 1950, for which the number of ER wells is unknown. There also are discrepancies among the numerous data sources available in historical documents and modern digital datasets (Fig. 4). We compare the data sources to estimate the potential degree of error, which is included as multiplicative factors of 1.3–1.5 in the upper bound estimate (*SI Appendix*, Table S4).

Methane Emission Estimates. The emission factors (Table 2) are combined with the number of wells in each well category in the Pennsylvania DEP database (24) (Fig. 5). The methane emissions contributed by gas wells and wells in coal areas are significantly larger than their share in well numbers. Considering each attribute independently, wells in coal areas represent 21% of the DEP database but 72% of the estimated methane emissions; similarly, gas wells represent 32% of the DEP database but 77% of the methane emissions (Fig. 5). Plugged wells, including those that are vented, represent an estimated 74% of the methane emissions, slightly

Table 2. Emission factors based on coal indicator, plugging status, and well type

	Emission factor (mg·h^{-1}·well^{-1})		No. of measured wells		SE	
Well type and coal area designation	Unplugged	Plugged	Unplugged	Plugged	Unplugged	Plugged
All						
None	2.2×10^4	11.5×10^4	53	35	9.2×10^3	1.0×10^4
Coal	1.2×10^3	4.3×10^4	17	12	9.9×10^2	2.9×10^4
Noncoal	3.1×10^4	4.5×10^2	36	23	1.3×10^4	2.8×10^2
Oil and combined oil and gas						
None	1.9×10^2	3.3×10^2	34	13	9.7×10^1	2.6×10^2
Coal	1.1	1.2×10^{-2}	13	1	9.1×10^{-1}	n/a
Noncoal	3.1×10^2	3.6×10^2	21	12	1.5×10^2	2.8×10^2
Gas						
None	6.0×10^4*	2.4×10^4	19	22	2.4×10^4	1.6×10^4
Coal	5.2×10^3	4.7×10^4*,†	4	11	3.9×10^3	3.2×10^4
Noncoal	7.5×10^4*	5.4×10^2	15	11	2.9×10^4	5.1×10^2

The emission factors are averages of mean methane flow rate measurements per well (mg·hour^{-1}·well^{-1}). The corresponding numbers of wells and SEs are shown in the next columns. Coal areas are defined here as wells that overlap with one or more workable coal seams. n/a, not applicable.

*The three highest emission factors are shown.

†The measured plugged wells in coal areas are vented as required by regulations.

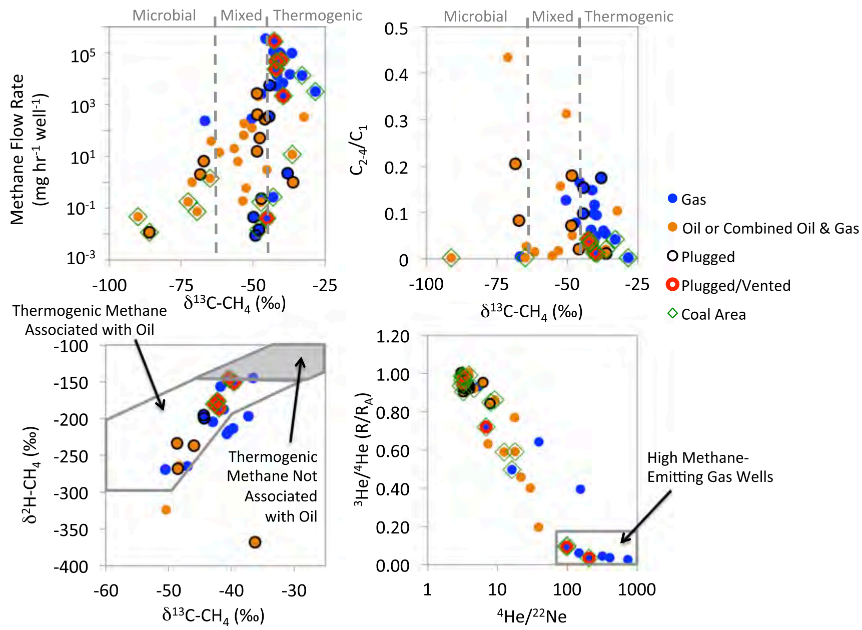

Fig. 3. Carbon and hydrogen isotopes of methane (δ^{13}C-CH_4 and δ^{2}H-CH_4), hydrocarbon concentration ratios (C_{2-4}/C_1), noble gas data, and methane flow rate data shown colored by well type, circled by plugging status, and marked with green diamond outlines if in a coal area. For repeat measurements, the average of the data for the well is shown. The regions representing thermogenic methane associated and not associated with oil are from ref. 17.

higher than the number for plugged wells (70%) in the DEP database. The DEP database does not distinguish between plugged wells and plugged/vented wells; both are simply categorized as plugged. In our estimate, plugged/vented wells are those that are both plugged and in coal areas, following regulatory requirements in Pennsylvania. Therefore, the methane emissions for all plugged wells (Fig. 5) represent both a large contribution from high methane-emitting plugged/vented gas wells (in coal areas) and a smaller contribution from low methane-emitting plugged wells that are not vented.

Our attribute-based methane emissions estimates for Pennsylvania using improved well numbers range from 0.04 to 0.07 Mt CH_4 per year, which correspond to 5–8% of estimated annual anthropogenic methane emissions for 2011 in Pennsylvania (*SI Appendix*).

Discussion

Methane Emissions. Well attributes determined for the measured wells in this paper likely remain unavailable for many wells across the United States. Therefore, well attribute estimation studies similar to this analysis may be valuable for many states. For example, West Virginia has at least 57,597 wells that were drilled before 1929 (34% of Pennsylvania wells over the same time period) (25), and records for many wells in the state are likely to be missing. Determining well attributes and numbers is as important as collecting additional measurements for estimating methane emissions. The attributes of high methane-emitting abandoned oil and gas wells identified here as plugging status (*P*), well type (*W*), and coal area designation (*C*) may also be indicative of high emitters elsewhere. In the United States, there are 31 oil-producing states, 33 natural gas-producing states, and 25 coal-producing states (30), with many states simultaneously producing oil, natural gas, and coal. Other well attributes, such as age, wellbore deviation, and operator (12), may also be predictors of methane flow rates. However, we do not explore these attributes here because of a lack of data. Efforts to collect and compile additional well attributes are needed to explore the role of attributes not considered in this study.

The total number of abandoned oil and gas wells remains uncertain in Pennsylvania and across the United States. Documented numbers of wells are more likely to represent lower bounds, because they may not include certain types of wells (e.g., injection wells for ER) and may be missing records. For example, the estimate of 3 million abandoned wells across the United States (4) does not include injection wells drilled for ER or undocumented wells. In addition, our upper limit in the number of abandoned wells in Pennsylvania of 750,000 may also be an underestimate because of uncertainties associated with differences in terminology among databases and the accuracy of modern digital databases, even in recent records (*SI Appendix*).

The uncertainties associated with well numbers may be addressed through the application of well-finding technologies (31), field verifications, and database updates. These activities can also help estimate well attributes. In addition, more field measurements of methane emissions are needed from abandoned wells with different attributes and in other geographical locations (i.e., states and countries) to reduce uncertainties in emission factors (32) (Table 2).

Mitigation. Targeting high emitters will lower mitigation costs per unit of methane emissions avoided. The identification of abandoned conventional gas wells and plugged/vented gas wells as the highest emitters allows government agencies to prioritize gas fields and coal areas in their mitigation efforts. Furthermore, explicit categorization of plugged/vented wells, which are found to be high emitters, in state databases may be useful. In addition to database analysis, noble gases, specifically low ^{3}He/^{4}He and high ^{4}He/^{22}Ne ratios, provide an independent approach to identify attributes of high methane-emitting abandoned wells.

Because abandoned wells emit methane continuously, over multiple years and presumably many decades, mitigating their emissions will have a larger apparent benefit when longer time periods are considered. Our multiyear measurements show that the high emitters are likely to emit methane at consistently high levels. Such wells may have been emitting at these levels for many decades and will likely continue for decades into the future. A comparison of the benefits of methane emissions reductions from abandoned wells with reductions from intermittent, short-term sources, such as unconventional oil/gas well development, should be performed using emissions integrated over many years.

Well plugging, which is currently viewed as the main mitigation solution (5, 10), does not guarantee a reduction in methane emissions. Plugging was required originally to protect oil and gas reservoirs, reduce risks of explosions, and more recently, protect groundwater. Plugged wells that are vented, as required by regulations in coal areas in Pennsylvania, are very likely to be high

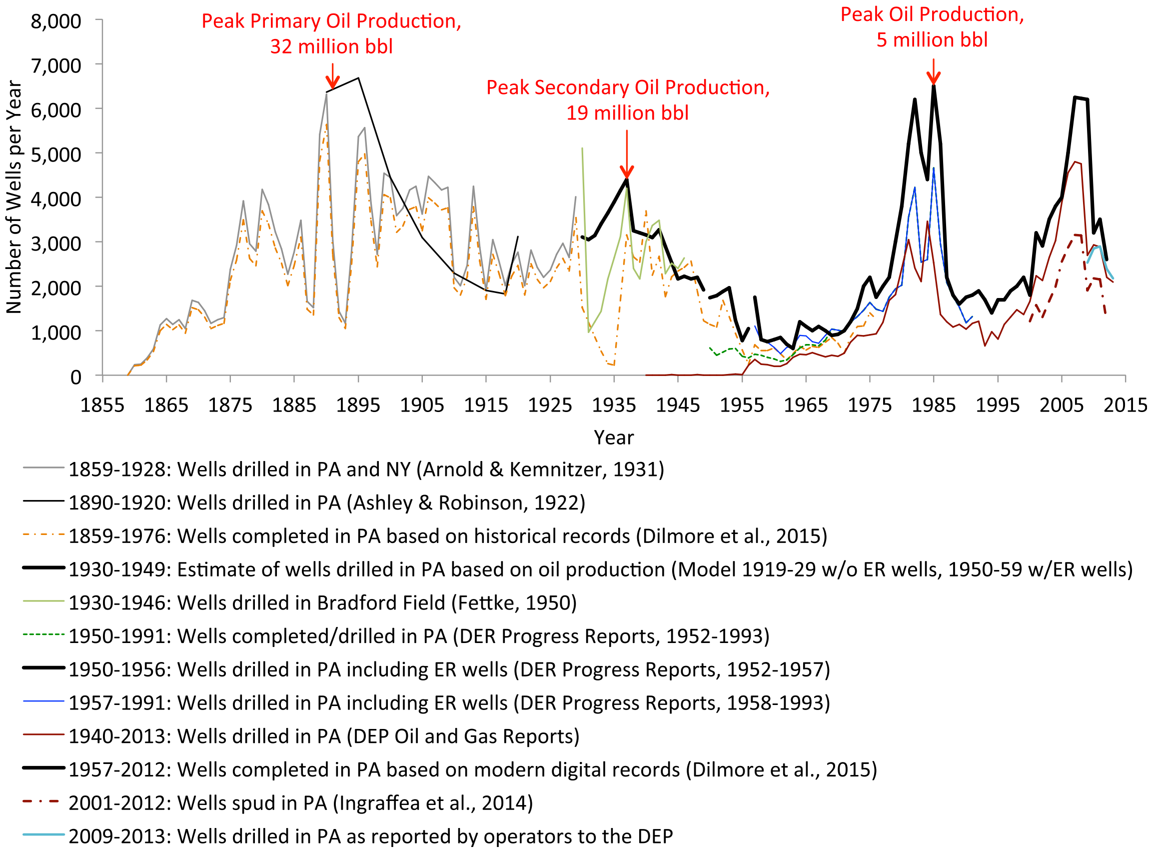

Fig. 4. Number of drilled and/or completed oil and gas wells in Pennsylvania from various historical documents and databases (*SI Appendix*). The thick black lines represent the 1929–2013 data used to estimate the total number of wells (*SI Appendix*, Table S4, second column). For 1859–1928, we use a total well number provided in ref. 25, and the curves shown here are not used to estimate well numbers.

emitters. There are many oil- and gas-producing states with geographically extensive coal layers (e.g., Colorado, Illinois, Indiana, Kentucky, Ohio, Oklahoma, Pennsylvania, West Virginia, and Wyoming). These states have special decommissioning or plugging requirements for coal areas (10). States that require venting in coal areas may want to consider alternatives that ensure safety while reducing methane emissions.

Conclusions

High methane-emitting abandoned wells are found to be unplugged gas wells in noncoal areas and plugged but vented gas wells in coal areas, and they seem to be unrelated to the presence of underground natural gas storage areas or unconventional oil/gas production. The identification of these high emitters provides an opportunity to target mitigation efforts and reduce mitigation costs.

Our attribute-based estimate of 5–8% of estimated annual anthropogenic methane emissions in Pennsylvania is higher than previous estimates, which were based on a single emission factor for all wells and a smaller well count (3, 8, 15). The methane flow rates characterized by well attributes may provide insight into potential emissions outside of Pennsylvania in the 33 oil- and gas-producing US states and other oil- and gas-producing countries. Using the analysis framework presented here, scientists and policymakers can better estimate methane emissions and develop cost-effective mitigation strategies for the millions of abandoned oil and gas wells across the United States and abroad.

Materials and Methods

Well Attributes and Numbers. To determine attributes of the measured wells and estimate the number of abandoned oil and gas wells, we combine information from different types of data sources: historical documents, published literature, field investigations, and state databases. Historical documents include Pennsylvania agency reports (26–28) and books (25, 33). State databases, including geospatial data, were obtained from the Pennsylvania Department of Conservation and Natural Resources (DCNR) (34) and the Pennsylvania DEP (24), agencies that emerged in 1995 from the Pennsylvania Department of Environmental Resources (DER). We combine and analyze the information to estimate attributes of measured wells based mainly on their location with respect to nearby or overlying oil/gas wells, pools, and fields with attributes in the DCNR database. The attributes determined are depth (d), coal area designation (C), plugging status (P), well type (W), distance to nearest natural gas storage field (r_S), and distance to nearest unconventional oil and gas well (r_U). To estimate the number of abandoned wells, we sum the number of wells drilled annually compiled from multiple sources (15, 24, 25, 27, 28, 33, 35) and subtract the number of active wells from the total (24). We include wells drilled for ER purposes and estimate missing well numbers by scaling available well and production data. We also compare data sources to quantify uncertainties in well numbers. Details on the attribute estimation methodology and the well number estimation are provided in *SI Appendix, SI Materials and Methods*.

Field and Laboratory Methods. The measurements of methane flow rates and light hydrocarbon (ethane, propane, and *n*-butane) concentrations (January, March, and June of 2015 samples) followed methods presented in ref. 3. The measurements were performed across seven counties in Pennsylvania (*SI Appendix*, Table S2). The measurements of methane isotopes were performed at Princeton University (3, 36) and Lawrence Berkeley National Laboratory (LBNL). At LBNL, we also analyzed hydrogen isotopes of methane if concentrations were sufficiently high (~1,200 ppmv). For October of 2014 and January, March, and June of 2015, we analyzed the samples for the following noble gases, He, Ne, and Ar, at Ohio State University following methods presented in ref. 22. Additional information on the field sampling and the analysis procedures is provided in *SI Appendix, SI Materials and Methods*.

Multilinear Regression. We perform a multilinear regression using the following linear model expressed in Wilkinson notation (37):

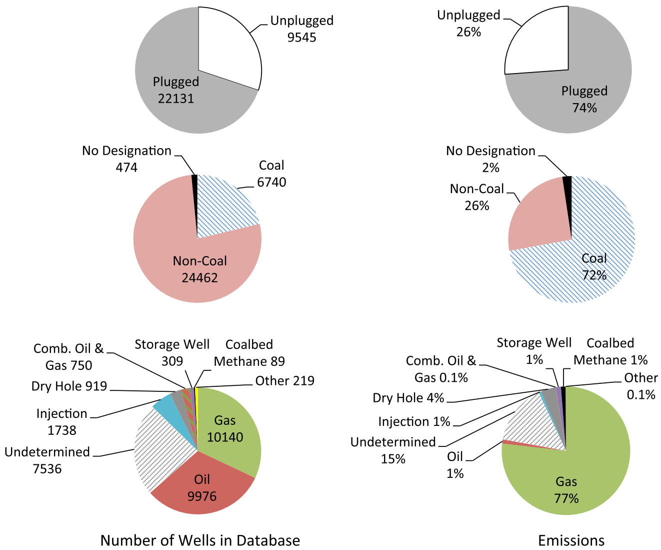

Fig. 5. Number of wells in the PA DEP database (*Left*) and the corresponding relative methane emissions distribution (*Right*) based on plugging status, coal area designation, and well type. Each of three attributes is considered independently.

$$\ln \dot{m} \sim 1 + d + C + P + W + r_S + r_U. \qquad [1]$$

Note that the categorical variables, *C*, *P*, and *W*, are denoted using uppercase letters. Multilinear regression is also performed on other linear models, which are summarized in *SI Appendix, SI Materials and Methods*.

Methane Emission Estimates. Based on the multilinear regression results, we use *C*, *P*, and *W* as the key attributes for methane emission estimation:

$$E_{\text{abandoned wells}} = \sum_w \sum_p \sum_c EF_{w,p,c} \cdot n_{w,p,c}, \qquad [2]$$

where *E* is the total methane emissions, *EF* is the emission factor, *n* is the number of wells, and subscripts *w*, *p*, and *c* represent the appropriate values of *W*, *P*, and *C*, respectively. We consider two well types (*w* = oil or combined oil & gas and gas), two plugging statuses (*P* = plugged and unplugged), and two coal area designations (*c* = coal and noncoal area). We use the Pennsylvania DEP's wells database (24) and the above attributes to determine the proportion of wells in each category. Additional details, including discussions on uncertainties, are given in *SI Appendix, SI Materials and Methods*.

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ENVIRONMENTAL SCIENCES

SUSTAINABILITY SCIENCE

June 13, 2022

Submitted via https://www.regulations.gov

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Donnique Sherman
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San Francisco, CA 94105

Re: Limited Approval, Limited Disapproval of California Air Plan Revisions; California Air Resources Board [Docket ID No. EPA–R09–OAR–2022–0416; FRL–9820–01–R9]

Dear Ms. Law, Ms. Sherman, and Ms. Schwenk-Mueller,

Thank you for accepting these comments submitted on behalf of Center for Biological Diversity, Central California Asthma Collaborative, Central Valley Air Quality Coalition, Clean Water Action, Earthjustice, Little Manila Rising, Mi Familia Vota, and Sierra Club (Kern-Kaweah Chapter) on EPA's proposed limited approval and limited disapproval of California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (Oil and Gas Methane Rule) into the California State Implementation Plan (SIP).

Commenters write to apprise EPA of recent evidence showing what appears to be a systematic failure to control significant leaks of volatile organic compounds (VOCs) from oil and gas wells in neighborhoods in Bakersfield, California. Although evidence about the cause and nature of these leaks is still developing, the leaks may fall within loopholes in the Oil and Gas Methane Rule and related local air district rules. Commenters write to emphasize that any such loopholes would preclude a finding that the State is implementing "reasonably available control technology" (RACT), as the Clean Air Act requires, and thus EPA must require the State to remedy any such loopholes in this rulemaking.

This past month, it has come to light that at least 30 wells in and nearby to Bakersfield neighborhoods are leaking methane.[1] Many of these wells are near homes, and some are leaking methane in such significant volumes that the air near the escaping gas is literally explosive.[2]

These leaks began to be discovered on May 10, 2022, when an energy analyst, visiting Bakersfield as part of a documentary on aging oil and gas infrastructure, noticed that two idle wells were audibly hissing within a few hundred feet of homes.[3] A week later, an inspector from the San

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[1] CalGEM, *Update on Bakersfield Idle Wells*, https://www.conservation.ca.gov/index/Pages/News/State-Oil-and-Gas-Supervisor-Issues-Statement-on-Two-Bakersfield-Long-Term-Idle-Wells.aspx (accessed June 8, 2022).
[2] Janet Wilson, *21 Oil Wells Now Found Leaking Methane Near California Homes*, Desert Sun (June 2, 2022), https://www.desertsun.com/story/news/environment/2022/06/02/number-oil-wells-leaking-methane-near-california-homes-climbs-21/7484046001/.
[3] Drew Costley, *Gas Wells Leak Explosive Levels of Methane in Bakersfield*, AP News (May 25, 2022), https://apnews.com/article/climate-science-health-california-and-environment-8ce6af934dcb5774f00c8e669df23bbb.

Joaquin Valley Unified Air Pollution Control District measured methane concentrations near the wells and confirmed that levels at one of the wells equaled or exceeded 50,000 parts per million (ppm)—which is the maximum the Air District can measure.[4] A methane expert characterized the measured concentration as "an extreme and potentially hazardous event."[5] While inspectors checked the two wells, they noticed four additional leaking idle wells, and the air nearby three of those wells also had methane concentrations at or above 50,000 ppm.[6] Inspectors have steadily discovered additional wells since then, and the current count of confirmed leaking wells in Bakersfield has reached 30.[7]

These leaks are undoubtedly the source of ozone-forming VOC emissions, and thus they implicate EPA's current rulemaking. To commenters' knowledge, inspectors have not tested these wells for VOCs. But, of course, "[m]ethane from the oil and gas industry comes packaged with . . . VOCs,"[8] and "both VOCs and methane are found in . . . raw oil and gas."[9] EPA therefore must assume these leaks are significant sources of VOCs. The scope of these and similar well leaks is unknown and potentially huge, with approximately 38,000 idle wells in California, and with studies suggesting that idle well leaks are widespread.[10]

EPA has a responsibility to use this rulemaking to protect California communities from these dangerous leaks. Little specific information about the leaks is publicly available, and we encourage EPA to work with interested and responsible parties to learn as much as possible about where the leaking wells fall within the regulatory scheme. EPA should then require the State and local air districts to remedy any loopholes or other inadequacies in the regulatory scheme that allowed the leaks to take place or that may allow similar leaks to take place. Such remediation plainly falls within the scope of the requirement in section 182(b)(2) of the Clean Air Act that the State implement RACT, which is defined as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."[11]

We are aware of one loophole that may have allowed some of the leaks to occur and persist without detection. Specifically, it appears that if a well within the jurisdiction of the San Joaquin Valley Unified Air Pollution Control District is used for oil with an American Petroleum Institute (API) gravity below 20 and is not steam-enhanced, that well is exempt from leak detection and repair (LDAR) requirements under the Oil and Gas Methane Rule and the San Joaquin Valley Air District's relevant local rules. The Oil and Gas Methane Rule itself, in Cal. Code Regs., title 17, section 95669(b)(2), exempts "components found on tanks, separators, wells, and pressure vessels []

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[4] *Inspectors Find 14th Oil Well Leaking Methane in Bakersfield Residential Area*, Bakersfield Californian (May 31, 2022), https://www.bakersfield.com/news/inspectors-find-14th-oil-well-leaking-methane-in-bakersfield-residential-area/article_76b33f18-e127-11ec-98ae-cbb404e66185.html.
[5] Costley, *supra*.
[6] *Id.*
[7] CalGEM, *supra*.
[8] U.S. EPA, *EPA's Actions to Reduce Methane Emissions from the Oil and Natural Gas Industry: Final Rules and Draft Information Collection Request* at 1, https://www.epa.gov/sites/default/files/2016-09/documents/nsps-overview-fs.pdf.
[9] CARB, *Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities – Staff Report: Initial Statement of Reasons* at 9 (May 31, 2016).
[10] Eric D. Lebel et al., *Methane Emissions from Abandoned Oil and Gas Wells in California*, Environ. Sci. Technol. 2020, 54, 22, 14617-14626 (Oct. 30, 2020), https://pubs.acs.org/doi/pdf/10.1021/acs.est.0c05279#.
[11] 57 Fed. Reg. 13,498, 13,541 (Apr. 16, 1992).

used exclusively for crude oil with an API gravity less than 20 averaged on an annual basis." San Joaquin Valley Rule 4401—which regulates VOC emissions from steam-enhanced crude oil production wells—applies only to components at wells that are steam-enhanced.[12] And San Joaquin Valley Rule 4409—which regulates VOC emissions from leaking components at light crude oil production facilities, natural gas production facilities, and natural gas processing facilities—does not apply to facilities used for oil with an API gravity below 30 degrees.[13]

It appears the Bakersfield wells—along with perhaps the majority of oil wells in California—fall within these exemptions. The Bakersfield wells at issue were not involved in steam injection. In addition, the oil from the two fields at issue of which commenters are aware had API gravities of 15.3 and 19.2, respectively, below the state and regional threshold for regulation.[14] The gravity denotes the density of crude oil, and oil is considered "heavy" if it has an API gravity from 10 to 22.3 degrees. In 2018, 68% of California's crude oil production was heavy.[15] Consequently, exempting equipment used for oil with an API gravity below 20 could allow a vast proportion of California's oil production to escape LDAR requirements.

Of course, other loopholes and exemptions from LDAR requirements in the Oil and Gas Methane Rule and local air district rules may have contributed to the current crisis and may contribute to similar crises in the future. We trust that EPA will take seriously this developing issue and will—consistent with the requirement that California implement RACT—identify and close any loopholes and inadequacies such as the one described above that allow for dangerous and accounted-for VOC leaks from oil and gas wells.

Respectfully Submitted,

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Sierra Club, Kern-Kaweah Chapter

(Enclosures)

[12] Rule 4401, § 2.0.
[13] Rule 4409, § 3.22.
[14] Cal. Air Res. Bd., *Low Carbon Fuel Standard Lookup Table* (2018), https://www.arb.ca.gov/fuels/lcfs/crude-oil/lookup_table_mcon_inputs_opgee_v2.0c_2018-0620.xlsm?_ga=2.215401111.1000142798.1654813760-210190253.1616441822 (showing Fruitvale Oil Field API gravity at 15.3 and Kern Bluff Oil Field API gravity at 19.2).
[15] Cal. Energy Com., *Petroleum Watch* (February 2020), https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf; see also Ctr. for Biological Diversity, *Killer Crude* (June 2021), https://www.biologicaldiversity.org/programs/climate_law_institute/pdfs/June-2021-Killer-Crude-Rpt.pdf.

Attachments

1. CalGEM, *Update on Bakersfield Idle Wells* (updated June 7, 2022)
2. Janet Wilson, *21 Oil Wells Now Found Leaking Methane Near California Homes*, Desert Sun (June 2, 2022)
3. Drew Costley, *Gas Wells Leak Explosive Levels of Methane in Bakersfield*, AP News (May 25, 2022)
4. *Inspectors Find 14th Oil Well Leaking Methane in Bakersfield Residential Area*, Bakersfield Californian (May 31, 2022)
5. U.S. EPA, *EPA's Actions to Reduce Methane Emissions from the Oil and Natural Gas Industry: Final Rules and Draft Information Collection Request*
6. Eric D. Lebel et al., *Methane Emissions from Abandoned Oil and Gas Wells in California*, Environ. Sci. Technol. 2020, 54, 22, 14617-14626 (Oct. 30, 2020) (abstract)
7. Cal. Energy Com., *Petroleum Watch* (February 2020)
8. Ctr. for Biological Diversity, *Killer Crude* (June 2021)
9. U.S. House of Reps. Com. on Sci., Space, and Tech., *Seeing CH4 Clearly* (June 2022)

Update on Bakersfield Idle Wells

Leer versión español

June 7, 2022
After inspecting an additional 20 wells owned by Citadel Exploration Inc, CalGEM staff have identified two more wells leaking methane. CalGEM is evaluating options for fixing the leaks on those wells. Citadel Exploration Inc is already subject to an enforcement order from CalGEM to permanently plug many of its wells in the nearby area.

CalGEM staff continues to monitor previously repaired wells in the area. Yesterday, staff identified low-level methane leaks from two of the previously repaired Zynergy wells. CalGEM will work with the contractor to make sure those wells are adequately repaired.

June 4, 2022
CalGEM continues to monitor the idle wells successfully repaired in the last two weeks and found no reportable methane emissions.

Zynergy, LLC wells in the Kern Bluff oil field
Work continues on the idle wells operated by Zynergy, LLC. Five of the seven wells have been repaired. Post-repair inspections show no methane leakage. Contractors continue to work on the two remaining wells.

Griffin Resources, LLC wells in the Fruitvale oil field
CalGEM contractors were able to access and depressurize a high-pressure well owned by Griffin Resources, LLC, and repaired the well to prevent further methane leakage. Inspectors also continue to monitor the well depressurized on May 30 and found no methane leaks, and gauges installed within the wells showed low pressure readings. CalGEM is evaluating options to ensure the leaks on the remaining six wells are quickly fixed.

Citadel Exploration Inc. wells in the Kern Bluff oil field
CARB staff, along with the San Joaquin Valley Air Pollution Control District and CalGEM, inspected an additional 18 wells owned by Citadel Exploration Inc. They found elevated methane emissions at

six of those wells. CalGEM is evaluating options for fixing the leaks on those wells.

E&B Natural Resources wells in the Fruitvale oil field
As part of an emergency enforcement order issued on May 16, CalGEM previously identified eight wells owned by E&B Natural Resources as needing to be repaired to address high pressure build-up within the well. CARB also inspected one of those wells and confirmed elevated methane emissions. E&B Natural Resources was able to repair the well that was leaking methane yesterday and continues work to depressurize the remaining seven wells.

June 1, 2022
Representatives from CARB and the San Joaquin Valley Air Pollution Control District are in the community today and tomorrow to interview residents and take additional methane readings.

Work continues on the idle wells operated by Zynergy, LLC. CalGEM inspectors confirmed that four of the wells are repaired and no longer leaking methane. Contractors are on site today to work on the remaining three wells.

CalGEM continues its inspection efforts for the 25 wells owned by Griffin Resources, LLC. One well was safely depressurized on May 30. CalGEM has identified another well owned by the company showing high pressure readings, and is working to gain access to the site where the well is located. Six other wells are showing low-level methane leaks, and CalGEM is evaluating options to ensure the leaks are quickly fixed. Over the weekend, the company appealed CalGEM's emergency order to permanently plug and decommission these wells and others (25 wells total).

May 31, 2022
Work continued this weekend on the seven idle wells operated by Zynergy LLC. CalGEM inspected all repair work to make sure methane emissions were eliminated, but found that some wells were still leaking methane. CalGEM and the operator were on site throughout the weekend to carefully monitor the wells. Work to fix the leaks continues.

Residents can find updates here and at the next community forum on Tuesday, May 31, at 6:00 p.m., which will include speakers from CalGEM, CARB, the San Joaquin Valley Air Pollution Control District and the Bakersfield Fire Department. The Zoom meeting will be hosted in both Spanish and English.

A separate inspection approximately ten miles away in North Bakersfield identified a leaking well owned by Griffin Resources, LLC, and CalGEM determined the well needed to be depressurized immediately to prevent further leaks. The Bakersfield Fire Department evaluated the site and determined the leak did not present an imminent danger. The Fire Department also took readings throughout the surrounding residential neighborhood and found no detectable levels of methane.

The Fire Department cut the gate lock on the site in order for CalGEM contractors to gain access the to well and depressurize it. That depressurization was completed on Monday, May 30 and additional repair work is underway today.

CalGEM previously looked at this site as part of an emergency enforcement effort for high pressure wells in the area. CalGEM issued an order two weeks ago to Griffin Resources, LLC, directing the company to permanently plug and abandon this well and another 24 wells in the Fruitvale oil field.

May 27, 2022

As part of the coordinated response between CalGEM, CARB, the San Joaquin Valley Air Pollution Control District and the Bakersfield Fire Department, two community forums will be hosted online to provide updates to local residents. Today's event will begin at 5:00 p.m., **and** another will be held Tuesday, May 31 at 6:00 p.m.

Both will be hosted on Zoom in Spanish and English.

Zynergy, LLC, began work yesterday to repair its wells north of the Morningstar neighborhood. The repair plans now include two additional wells that CalGEM and the San Joaquin Valley Air Pollution Control District identified with lower but still notable methane readings. CalGEM will work with the operator to ensure all seven wells are repaired in order to eliminate methane emissions and carefully monitor any well pressure.

May 26, 2022

While local first responders have determined that the methane leaks do not pose an immediate danger, CalGEM, CARB, the San Joaquin Valley Air Pollution Control District, and Bakersfield Fire Department continue their efforts to identify methane leaks from idle wells near the Morningstar neighborhood, coordinate on response, and assess options to ensure operators are held accountable.

All six leaking Sunray Petroleum wells near the Morningstar neighborhood have been repaired. A post-repair inspection detected no methane emissions.

Yesterday, CalGEM and the San Joaquin Valley Air Pollution Control District inspected an additional 21 idle wells approximately half-a-mile north of the Morningstar neighborhood.

Five of these wells were found to be leaking elevated concentrations of methane at the wellsite; however, no methane levels were detected upon stepping away from the well. CalGEM immediately contacted the operator, Zynergy LLC, which has contractors on site today to remediate the leaks. The Bakersfield Fire Department was again on-site and determined that the leaks do not present an immediate danger.

We will continue to provide updates as new information becomes available.

May 25, 2022

An inspection of additional wells conducted by CalGEM and California Air Resources Board (CARB) on Saturday, May 21, found similar leaks at four other idle wells operated by Sunray Petroleum in northeast Bakersfield. Again, local first responders determined there is no immediate threat to public health or safety. Though detected methane levels were far below public safety reporting thresholds, CalGEM has dispatched workers to seal the leaks to prevent methane emissions. As each well is sealed, CalGEM has installed gauges to allow inspectors to monitor any pressure inside the well. On each repaired well inspectors have found no pressure or cause for concern.

Readings were also taken within the boundary of the residential neighborhood and found no detectable levels of methane. Our team is now conducting additional idle wells inspections in nearby residential areas. Those inspections will be completed this week.

CalGEM is coordinating with local first responders, including the Bakersfield Fire Department, who have determined the wells do not pose an immediate threat to public health or safety. We are committed to protecting public safety and keeping the community informed, and will do so through a partnership between CalGEM, CARB and the San Joaquin Valley Air Pollution Control District as we complete the remaining work.

May 20, 2022

Bakersfield, California – California State Oil and Gas Supervisor Uduak-Joe Ntuk issued the following statement on two long-term idle wells in Bakersfield, California that were discovered to be leaking and are now repaired:

"CalGEM deployed inspectors yesterday to evaluate the methane emissions from two long term idle wells operated by Sunray Petroleum. We have been coordinating with the operator and local first responders to determine the wells do not pose an immediate threat to public health or safety. While the pinhole-sized leaks were determined to be minor in nature, CalGEM contractors were able to seal both wells today."

Background

The San Joaquin Valley Air Pollution Control District (SJVAPCD) conducted an inspection and found elevated methane readings on May 17, 2022. The leak was determined not to be an emergency situation by Bakersfield Fire Department.

Upon receiving notification of potentially high levels of methane emissions leaking from two long term idle wells in Kern Bluff Lease, CalGEM took immediate action to deploy field engineers to inspect the site and file a notification with the Governor's Office of Emergency Services. After inspecting the site and consulting with Bakersfield Fire Department and the SJVAPCD, CalGEM can confirm that the wells were leaking methane gas, but the emissions do not rise to an emergency situation. To address the leak, CalGEM secured a contractor to seal and repair both wells.

Additionally, on May 2, CalGEM issued an Order to Sunray Petroleum, Inc. to plug and abandon wells, decommission production facilities, and restore well sites for 28 idle wells, including the two wells that were discovered to be leaking. The Order was issued in response to a failure to pay idle well fees and submit an Idle Well Testing Compliance work plan as well as numerous oilfield related violations ranging from missing well signs, cellars full of fluid, and missing bolts on wellheads, to out-of-service facility requirements not being satisfied. Sunray Petroleum, Inc., appealed that order on May 13 and the matter will be heard by an administrative law judge with the Office of Administrative Hearings.

Established in 1915, CalGEM is tasked with regulatory jurisdiction over oil and gas fields, underground natural gas storage facilities, and geothermal energy operations. Regulatory authority covers the upstream (oil fields) portion of the oil industry which includes more than 242,000 wells across California, including nearly 101,300 which are defined as active or idle oil producers.
For more information, visit CalGEM's website.

Actualización sobre los pozos inactivos de Bakersfield

7 de junio de 2022
Después de inspeccionar 20 pozos adicionales propiedad de Citadel Exploration Inc, el personal de CalGEM identificó dos pozos más con fugas de metano. CalGEM está evaluando opciones para reparar las fugas en esos pozos. Citadel Exploration Inc ya está sujeta a una orden de ejecución de CalGEM para tapar permanentemente muchos de sus pozos en la zona cercana.

El personal de CalGEM continúa monitoreando los pozos que fueron reparados previamente en la zona. Ayer, el personal identificó fugas de metano de bajo nivel en dos de los pozos de Zynergy que fueron reparados anteriormente. CalGEM trabajará con el contratista para asegurarse de que esos pozos se reparen adecuadamente.

4 de junio de 2022
CalGEM continúa monitoreando los pozos inactivos que fueron reparados con éxito en las últimas dos semanas y no encontró emisiones de metano reportables.

Pozos de Zynergy, LLC en el campo petrolero de Kern Bluff

El trabajo continúa en los pozos inactivos operados por Zynergy, LLC. Cinco de los siete pozos han sido reparados. Las inspecciones posteriores a la reparación no muestran fugas de metano. Los contratistas continúan trabajando en los dos pozos restantes.

Pozos de Griffin Resources, LLC en el campo petrolero de Fruitvale
Los contratistas de CalGEM pudieron acceder y despresurizar un pozo de alta presión propiedad de Griffin Resources, LLC, y repararon el pozo para evitar más fugas de metano. Los inspectores también continúan monitoreando el pozo despresurizado y el 30 de mayo no detectaron fugas de metano, y los medidores instalados dentro de los pozos mostraron lecturas de baja presión. CalGEM está evaluando opciones para garantizar que las fugas en los seis pozos restantes sean reparadas rápidamente.

Pozos de Citadel Exploration Inc. en el campo petrolero de Kern Bluff
El personal de CARB, junto con el Distrito de Control de la Contaminación del Aire del Valle de San Joaquín y CalGEM, inspeccionaron 18 pozos adicionales propiedad de Citadel Exploration Inc. Se registraron emisiones elevadas de metano en seis de esos pozos. CalGEM está evaluando opciones para reparar las fugas en esos pozos.

Pozos de E&B Natural Resources en el campo petrolero de Fruitvale
Como parte de una orden de ejecución de emergencia emitida el 16 de mayo, CalGEM identificó previamente ocho pozos propiedad de E&B Natural Resources que necesitaban ser reparados para abordar la acumulación de alta presión dentro del pozo. CARB también inspeccionó uno de esos pozos y confirmó emisiones elevadas de metano. E&B Natural Resources pudo reparar el pozo que tenía fugas de metano ayer y continúa trabajando para despresurizar los siete pozos restantes.

1 de junio de 2022
Representantes de CARB y del Distrito de Control de la Contaminación del Aire del Valle de San Joaquín estarán en la comunidad hoy y mañana para entrevistar a los residentes y tomar lecturas adicionales de metano.

El trabajo continúa en los pozos inactivos operados por Zynergy, LLC. Los inspectores de CalGEM confirmaron que cuatro de los pozos están reparados y ya no tienen fugas de metano. Los contratistas están en el sitio hoy para trabajar en los tres pozos restantes.

CalGEM continúa con sus esfuerzos de inspección de los 25 pozos propiedad de Griffin Resources, LLC. Un pozo fue despresurizado de forma segura el 30 de mayo. CalGEM ha identificado otro pozo propiedad de la empresa que muestra lecturas de alta presión y está trabajando para obtener acceso al sitio donde se encuentra el pozo. Otros seis pozos muestran fugas de metano de bajo nivel y CalGEM está evaluando opciones para garantizar que las fugas se solucionen rápidamente. Durante el fin de semana, la empresa apeló la orden de emergencia de CalGEM para tapar y desmantelar permanentemente estos pozos y otros (25 pozos en total).

31 de mayo de 2022

Este fin de semana han continuado los trabajos en los siete pozos inactivos operados por Zynergy LLC. CalGEM inspeccionó todos los trabajos de reparación para asegurarse de que se eliminaban las emisiones de metano, pero descubrió que algunos pozos seguían teniendo fugas de metano. CalGEM y el operador estuvieron en el lugar durante todo el fin de semana para supervisar cuidadosamente los pozos. Los trabajos para arreglar las fugas continúan.

Los residentes pueden encontrar información actualizada aquí y en el próximo foro de la comunidad el martes 31 de mayo a las 6:00 p.m., que incluirá oradores de CalGEM, CARB, el Distrito de Control de la Contaminación del Aire del Valle de San Joaquín y el Departamento de Bomberos de Bakersfield. La reunión de Zoom se celebrará tanto en español como en inglés.

Una inspección separada a aproximadamente diez millas de distancia en el norte de Bakersfield identificó un pozo con fugas que es propiedad de Griffin Resources, LLC, y CalGEM determinó que el pozo necesitaba ser despresurizado inmediatamente para evitar más fugas. El Departamento de Bomberos de Bakersfield evaluó el lugar y determinó que la fuga no representaba un peligro inminente. El Departamento de Bomberos también tomó lecturas o mediciones en todo el vecindario residencial circundante y no encontró niveles detectables de metano.

El Departamento de Bomberos cortó la cerradura de la puerta para que los contratistas de CalGEM pudieran acceder al pozo y despresurizarlo. Tal despresurización se completó el lunes 30 de mayo y hoy se están realizando trabajos de reparación adicionales.

CalGEM examinó previamente este lugar como parte de un esfuerzo de aplicación de la ley de emergencia para los pozos de alta presión en la zona. CalGEM emitió una orden hace dos semanas a Griffin Resources, LLC, ordenando a la empresa a tapar y abandonar permanentemente este pozo y otros 24 pozos en el campo petrolífero de Fruitvale.

27 de mayo de 2022

Como parte de la respuesta coordinada entre CalGEM, CARB, el Distrito de Control de la Contaminación del Aire del Valle de San Joaquín y el Departamento de Bomberos de Bakersfield, se celebrarán dos foros comunitarios en línea para proporcionar información actualizada a los residentes locales. El evento de hoy comenzará a las 5 pm, y otro se celebrará el martes 31 de mayo a las 6 pm.

Ambos serán por Zoom en español e inglés.

Zynergy, LLC, comenzó a trabajar ayer para reparar sus pozos al norte del vecindario de Morningstar. Los planes de reparación incluyen ahora dos pozos adicionales que CalGEM y el Distrito de Control de la Contaminación del Aire del Valle de San Joaquín identificaron con mediciones o lecturas de metano más bajas pero aún notables. CalGEM trabajará con el operador para garantizar que los siete pozos sean reparados con el fin de eliminar las emisiones de metano y vigilar cuidadosamente la presión de los pozos.

26 de mayo de 2022

Aunque los servicios de emergencias locales han determinado que las fugas de metano no suponen un peligro inmediato, CalGEM, CARB, el Distrito de Control de la Contaminación del Aire del Valle de San Joaquín y el Departamento de Bomberos de Bakersfield siguen esforzándose por identificar las fugas de metano de los pozos inactivos cercanos al vecindario de Morningstar, coordinar la respuesta y evaluar las opciones para garantizar que los operadores rindan cuentas.

Los seis pozos con fugas de Sunray Petroleum cerca del vecindario de Morningstar han sido reparados. Una inspección posterior a la reparación no detectó emisiones de metano.

Ayer, CalGEM y el Distrito de Control de la Contaminación del Aire del Valle de San Joaquín inspeccionaron otros 21 pozos inactivos aproximadamente a media milla al norte del vecindario de Morningstar.

Se descubrió que cinco de estos pozos presentaban concentraciones elevadas de metano en el emplazamiento o sitio del pozo; sin embargo, no se detectaron niveles de metano al alejarse del pozo. CalGEM se puso inmediatamente en contacto con el operador, Zynergy LLC, que tiene contratistas en el lugar para remediar las fugas. El Departamento de Bomberos de Bakersfield estuvo de nuevo en el lugar y determinó que las fugas no representan un peligro inmediato.

Seguiremos proporcionando actualizaciones a medida que se disponga de nueva información.

25 de mayo de 2022

Una inspección de pozos adicionales realizada por CalGEM y la Junta de Recursos del Aire de California (CARB), el sábado 21 de mayo, encontró fugas similares en otros cuatro pozos inactivos operados por Sunray Petroleum en el noreste de Bakersfield.
Una vez más, los servicios de emergencia a nivel local determinaron que no hay una amenaza inmediata para la salud o la seguridad pública. Aunque los niveles de metano detectados estaban muy por debajo de los umbrales de notificación de seguridad pública, CalGEM ha enviado trabajadores para sellar las fugas y evitar las emisiones de metano. A medida que se va sellando cada pozo, CalGEM ha instalado manómetros para que los inspectores puedan controlar cualquier presión que haya dentro del pozo. En cada uno de los pozos reparados, los inspectores no han encontrado presión ni motivo de preocupación.

También se tomaron lecturas o mediciones dentro de los límites del vecindario residencial, y no se encontraron niveles detectables de metano. Nuestro equipo está llevando a cabo otras inspecciones de pozos inactivos en zonas residenciales cercanas. Esas inspecciones se completarán esta semana.

CalGEM está coordinando con los servicios de emergencia a nivel local, incluyendo el Departamento de Bomberos de Bakersfield, quienes han determinado que los pozos no representan una amenaza inmediata para la salud o la seguridad pública. Nos comprometemos a proteger la seguridad pública y a mantener informada a la comunidad, y lo haremos a través de una asociación entre CalGEM, CARB y el Distrito de Control de la Contaminación del Aire del Valle de San Joaquín mientras completamos el trabajo restante.

20 de mayo de 2022
Bakersfield, California - El supervisor de gas y petróleo del estado de California, Uduak-Joe Ntuk ha emitido la siguiente declaración sobre dos pozos inactivos durante mucho tiempo en Bakersfield, California, en los que se descubrieron fugas y que ya están reparadas:

"CalGEM desplegó ayer inspectores para evaluar las emisiones de metano de dos pozos inactivos de larga duración operados por Sunray Petroleum. Hemos coordinado esfuerzos con el operador y los servicios de emergencia a nivel local para determinar que los pozos no suponen una amenaza inmediata para la salud o la seguridad pública. Aunque se determinó que las fugas del tamaño de un alfiler eran de naturaleza menor, los contratistas de CalGEM pudieron sellar ambos pozos hoy".

Información de antecedentes
El Distrito de Control de la Contaminación del Aire del Valle de San Joaquín (SJVAPCD) realizó una inspección y encontró lecturas o mediciones elevadas de metano el 17 de mayo de 2022. El Departamento de Bomberos de Bakersfield determinó que la fuga no era una situación de emergencia.

Al recibir la notificación de la existencia de niveles potencialmente altos de emisiones de metano que se filtraban de dos pozos inactivos desde hace mucho tiempo en Kern Bluff Lease, CalGEM tomó medidas inmediatas para desplegar ingenieros de campo para inspeccionar el lugar y presentar una notificación a la Oficina del Gobernador de Servicios de Emergencia. Después de inspeccionar el lugar y consultar con el Departamento de Bomberos de Bakersfield y el SJVAPCD, CalGEM puede confirmar que los pozos tenían una fuga de gas metano, pero las emisiones no llegan a una situación de emergencia. Para solucionar la fuga, CalGEM consiguió que un contratista sellara y reparara ambos pozos.

Además, el 2 de mayo, CalGEM emitió una orden a Sunray Petroleum, Inc., para que taponara y abandonara los pozos, desmantelara las instalaciones de producción y restaurara los emplazamientos o sitios de 28 pozos inactivos, incluidos los dos pozos en los que se descubrieron fugas. La orden se emitió en respuesta al incumplimiento del pago de las tasas por pozos inactivos y de la presentación de un plan de trabajo para el cumplimiento de las pruebas de pozos inactivos, así como a numerosas infracciones relacionadas con los yacimientos petrolíferos, que van desde la falta de señalización de los pozos, las bodegas llenas de líquido y la falta de pernos en las cabezas de pozo, hasta el incumplimiento de los requisitos de las instalaciones fuera de servicio. Sunray

Petroleum, Inc., apeló esa orden el 13 de mayo y el asunto será escuchado por un juez de derecho administrativo de la Oficina de Audiencias Administrativas.

Creada en 1915, CalGEM tiene la misión de regular los yacimientos de petróleo y gas, las instalaciones de almacenamiento subterráneo de gas natural y las operaciones de energía geotérmica. La autoridad reguladora cubre la parte de aguas arriba (los campos petroleros) de la industria petrolera que incluye más de 242.000 pozos en todo California, incluidos casi 101.300 que se definen como productores de petróleo activos o inactivos. Para más información, visite la página web de CalGEM.

INDEX MENU

Desert Sun.

ENVIRONMENT

21 oil wells now found leaking methane near California homes

Janet Wilson
Palm Springs Desert Sun

Published 10:04 a.m. PT June 2, 2022 | Updated 11:01 a.m. PT June 2, 2022

A total of 21 oil wells have been found to be leaking methane in or near two Bakersfield neighborhoods, and more than two dozen are being tested by state and regional air regulators.

California Geologic Energy Management Division, or CalGEM, said in an update on its website that state and regional air regulators are in the area again today to interview residents and take additional methane readings.

Repairs are at various stages for the nearly two dozen wells, several of which were found to be leaking at least 50,000 parts per million of methane — a level at which the colorless, odorless gas can explode if ignited.

Six wells owned by Sunray near the Morning Star neighborhood were tested again on Wednesday and are no longer leaking after a contractor hired by CalGEM temporarily plugged them.

Work continues on seven idle wells operated by Zynergy in the same area. CalGEM inspectors confirmed that four of the wells are repaired and no longer leaking methane. Contractors are on site Thursday to work on the remaining three wells.

A state staffer told The Desert Sun last week that California's top oil regulator was "lying" about the level of risks at the sites, and said methane can build up underground in tight spaces and explode also. Since then, CalGEM announced it was installing pressure monitors on at least some of the wells as they are repaired or closed off.

CalGEM continues its inspection efforts for the 25 wells owned by Griffin Resources. One well that was hissing and emitting high levels of methane over Memorial Day weekend was safely depressurized on May 30. The agency has identified another well owned by the company showing high pressure readings, and is working to gain access to the site where the well is located.

Six other wells are showing low-level methane leaks, and CalGEM is evaluating options to ensure the leaks are quickly fixed. Over the weekend, the company appealed CalGEM's emergency order to permanently plug and decommission these wells and 17 others. Sunray has also appealed a CalGEM order to address problems at five oil fields across central California, saying in a letter that it has addressed many of the problems.

Idled wells are a burgeoning problem in California's century-old oil fields. A state study concluded two years ago that taxpayers could be saddled with more than $1 billion in cleanup costs if operators walk away from their responsibilities to properly plug and abandon them.

A report released Thursday by a consumer advocacy group and a coalition of environmental justice groups concludes costs associated with the industry to the state could top $10 trillion by 2045. Industry advocates say locally produced oil is vital, and is done under some of the strictest regulations in the world.

Janet Wilson is senior environment reporter for The Desert Sun, and co-authors USA Today's Climate Point newsletter. She can be reached at jwilson@gannett.com or @janetwilson66 on Twitter

Gas wells leak explosive levels of methane in Bakersfield

BY DREW COSTLEYMay 25, 2022

A pumpjack operates on Jan. 15, 2015, in Bakersfield, Calif. Residents of Bakersfield are concerned about potential explosions after a state agency found that six idle oil wells near homes were leaking methane in the past several days. (AP Photo/Jae C. Hong)

Some Bakersfield residents are concerned about potential explosions after a state agency found that six idle oil wells near homes were leaking methane in the past several days.

State and regional inspectors found concentrations of methane in the air around some of the wells at levels considered potentially explosive and environmental activists in the region are worried that other chemicals may also be leaking from the wells that could pose a threat to public health.

But Uduak-Joe Ntuk, head of the California Geologic Energy Management division of the California Department of Conservation, the agency that oversees wells and confirmed they were leaking, said in a statement that the leaks were “minor in nature and do not pose an immediate threat to public health or safety.”

Residents and environmentalists in the region first became concerned when they were alerted by Clark Williams-Derry, an energy analyst, that two wells were hissing within a few hundred feet of homes. He was visiting the area on May 10 with a French documentary crew that’s working on a film about cleaning up oil and gas infrastructure around the globe.

“One of them was leaking, it was making an audible hiss,” Williams-Derry told the Associated Press. “And I was like ‘what the hell is going on?’ I thought these things were supposed to be essentially sealed.”

On May 17, an inspector from the San Joaquin Valley Air Pollution Control District measured the concentrations of methane in the air surrounding the leaking wells, Jaime Holt, chief communications officer with the district, said in a statement to the Associated Press.

The agency wouldn’t confirm the concentrations of methane they found. But a letter sent to the state’s oil and gas regulators by a coalition of environmental groups said the inspector found that methane levels in the air around one of the wells was 20,000 parts per million (ppm) and at least 50,000 ppm around the other well.

Those two wells have since been sealed, Ntuk said in a statement on Friday, but while inspectors were checking to make sure the seals on those wells stopped the leaks, they found four more idle wells leaking.

Three of the four wells had methane concentrations of 50,000 ppm in the air surrounding them, according to a report from the state. The other well had a methane concentration of 6,000 ppm.

Methane is potentially explosive at air concentrations of 50,000 ppm, according to federal guidelines.

Riley Duren, an international methane expert and research scientist at the Arizona Institute for Resilient Environments and Societies and Research, Innovation and Impact, said that methane concentrations of 50,000 ppm can imply “an extreme and potentially hazardous event.”

CalGEM said in their report on the four additional leaks that they were notifying the owner/operators of the wells, Sunray Petroleum, to repair the leaks and that they briefed the Bakersfield Fire Department. But environmental advocates in the region said the response by regional and state authorities did not go far enough.

“The response… (shows) complete disrespect for the safety of this community,” said Nayamin Martinez, director of the Central California Environmental Justice Network and a resident of the area, in a statement.

CalGEM said there was no reason to alert the public of the leaks, but advocates in the region disagree. In the days following discovery of the leaks, Cesar Aguirre, senior community organizer for the Central California Environmental Justice Network, canvassed the neighborhood surrounding the wells to notify residents.

Aguirre said he was warning residents about the potential of an explosion or fire in their community, but also about other possible pollution, like acute levels of ozone or smog, that might be forming around the leaking wells. Methane itself is usually non-toxic to humans, but a 2021 report from the United Nations points out ozone pollution is tied to methane emissions.

“Methane is a health precursor, which means that it never shows up alone,” Aguirre said. “So if there’s methane, there’s definitely other scary chemicals that are floating around with it.”

David J.X. González, lead author on a recent study on the distribution of abandoned wells in urban areas, echoed some of Aguirre’s concerns and said the leaks are an “urgent public health issue.” He pointed out there are thousands of other idle wells spread throughout the state.

“Researchers have found that methane emissions from abandoned wells, which are disproportionately located in Black and Latinx neighborhoods, likely means other air toxics are being emitted too, which can cause birth defects, neurological damage, impaired hearing, and some cancers,” he said in a statement.

The neighborhoods near the leaking wells are between 20% and 70% Hispanic or Latino, according to the 2020 Census.

The coalition of groups pushing for the wells to be sealed hope the discovery of these leaks pushes the state to take action to ensure other idle wells throughout the state aren’t leaking methane, a potent greenhouse gas. The leaking wells represent damage to the climate as well along with the health concerns.

“We… hope this will spur CalGEM to move swiftly to address the tens of thousands of other idle or near-idle wells across the state to prevent these types of accidences in the future,” they said at the end of the letter.

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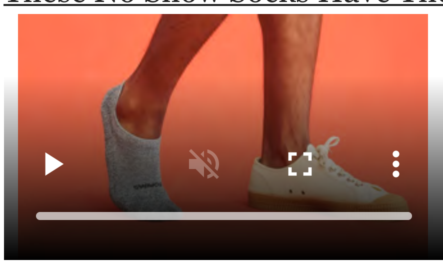
Follow Drew Costley on Twitter: @drewcostley.

The Associated Press Health and Science Department receives support from the Howard Hughes Medical Institute's Department of Science Education. The AP is solely responsible for all content.

This story was first published on May 24, 2022. It was updated on May 25, 2022 to correct the spelling of the name of Jaime Holt of the San Joaquin Valley Air Pollution Control District.



https://www.bakersfield.com/news/inspectors-find-14th-oil-well-leaking-methane-in-bakersfield-residential-area/article_76b33f18-e127-11ec-98ae-cbb404e66185.html

Inspectors find 14th oil well leaking methane in Bakersfield residential area

The Bakersfield Californian
May 31, 2022

Idle oil wells found to have been leaking methane, marked with blue bins, can be seen from a housing development on Morningstar Avenue. Authorities have said they do not know how much methane had been escaping from these wells, which are located as close as an eighth of a mile from the neighborhood.

Eliza Green / The Californian

State regulators have discovered another oil well leaking methane in a residential area in Bakersfield, bringing to 14 the number found fitting that description in the past two weeks.

According to information the state Department of Conservation provided Tuesday, the leak was found in the vicinity of 216 Durham Court, which is northeast of the intersection of California Avenue and Stockdale Highway, at a facility operated by Griffin Resources LLC. The previous batch of leaky wells was located in northeast Bakersfield near the intersection of Morning Drive and Morningstar Avenue.

Information posted by the California Office of Emergency Services said methane coming from the well measured 50,000 parts per million, the same as nine idle wells discovered earlier in May. That's the maximum concentration measurable using equipment available at the site.

A determination was made that the well found to be leaking Saturday needed to be depressurized immediately "to prevent further leaks," according to the online notice. It said the Bakersfield Fire Department determined the leak presented no immediate danger, which in past incidents meant only that the gas was not accumulating.

Tuesday's post said the well was depressurized Monday, repair work was being done Tuesday and tests in the "surrounding residential neighborhood" turned up no detectable levels of methane.

The department said the agency most directly responsible for oil regulation, its California Geologic Energy Management Division, sent Griffin Resources an order two weeks ago directing the company to permanently plug and abandon that well and 24 others in the Fruitvale Oil Field.

Editor's note: This story has been updated with additional information by CalGEM and CalOES.

MORE INFORMATION

Authorities lack methane data from local oil well leaks

Leaky oil well count hits 21

EPA's Actions to Reduce Methane Emissions from the Oil and Natural Gas Industry: Final Rules and Draft Information Collection Request

Overview

- On May 12, 2016, the U.S. Environmental Protection Agency (EPA) took another set of steps under the President's *Climate Action Plan: Strategy to Reduce Methane Emissions* and the Clean Air Act to cut methane emissions from the large and complex oil and natural gas industry and keep the Administration on track to achieve its goal of cutting methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025.

- EPA's actions include three final rules that together will curb emissions of methane, smog-forming volatile organic compounds (VOCs) and toxic air pollutants such as benzene from new, reconstructed and modified oil and gas sources, while providing greater certainty about Clean Air Act permitting requirements for the industry.

- EPA also took a critical step needed to carry out the Administration's commitment to regulate methane emissions from *existing* oil and gas sources: the agency issued for public comment an Information Collection Request (ICR) that will require companies to provide extensive information instrumental for developing comprehensive regulations to reduce methane emissions from existing oil and gas sources.

- Methane, the key constituent of natural gas, has a global warming potential more than 25 times greater than that of carbon dioxide. Methane is the second most prevalent greenhouse gas emitted by human activities in the United States, and approximately one-third of those emissions come from oil production and the production, processing, transmission and storage of natural gas.

- Methane from the oil and gas industry comes packaged with other pollutants: VOCs, which are a key ingredient in ground-level ozone (smog); and a number of pollutants known as "air toxics" – in particular, benzene, toluene, ethylbenzene and xylene.

- Ozone is linked to a variety of serious public health effects, including reduced lung function, asthma attacks, asthma development, emergency room visits and hospital admissions, and early death from respiratory and cardiovascular causes. Air toxics are known or suspected to cause cancer and other serious health effects.

- The methane reductions from the final New Source Performance Standards (NSPS) will build on the agency's 2012 rules to curb VOC emissions from new, reconstructed and modified sources in the oil and gas industry. EPA's final rule will get more methane reductions than estimated at proposal because of changes made in response to the more the 900,000 public comments we received. For example, the final rule requires low production wells to monitor leaks, rather than exempting them as proposed. Also, the final rule requires compressor stations to monitor leaks four times a year, rather than twice a year.

- Reducing methane emissions is an essential part of an overall strategy to address climate change. Climate change impacts affect all Americans' lives, from stronger storms and longer droughts to increased insurance premiums, food prices and allergy seasons. The most vulnerable among us -- including children, older adults, people with heart or lung disease and people living in poverty – are most at risk from the impacts of climate change.
- The reductions from the final NSPS, along with methane reductions from EPA's new Natural Gas STAR: Methane Challenge Program and actions by other federal agencies, will help the country continue moving toward safe and responsible oil and natural gas development.
- EPA also is working to complete final Control Techniques Guidelines (CTGs) for reducing VOC emissions from existing oil and gas sources in certain ozone nonattainment areas and states in the Ozone Transport Region. The agency anticipates issuing the CTGs later this spring.

Summary of Actions

Reducing Methane and VOCs from New and Modified Sources

- Building on its 2012 requirements to reduce VOC emissions, EPA has updated the NSPS for the oil and gas industry to add requirements that the industry reduce emissions of greenhouse gases and to cover additional equipment and activities in the oil and gas production chain. The final rule will accomplish this by setting emissions limits for methane, which is the principal greenhouse gas emitted by equipment and processes in the oil and gas sector. Owners/operators will be able to meet the limits using technologies that are cost-effective and readily available.

- The final NSPS will yield significant reductions in methane emissions from new, reconstructed and modified processes and equipment, along with reducing VOC emissions from sources not covered in the agency's 2012 rules. These sources include hydraulically fractured oil wells, some of which can contain a large amount of gas along with oil, and equipment used across the industry that was not regulated in the agency's 2012 rules.
- The final rule also requires owners/operators to find and repair leaks, also known as "fugitive emissions," which can be a significant source of both methane and VOC pollution.
- Most sources subject to the 2012 VOC reduction requirements now also are covered by the new requirements to reduce methane. However, they will not have to install additional controls, because the controls to reduce VOCs also reduce methane.

- EPA made a number of changes to the final rule based on information received during the public comment period. The final rule:
  - *Sets a fixed schedule for monitoring leaks.* The final rule sets a fixed schedule for monitoring leaks rather than a schedule that varies with performance. For well sites, including low-production well sites, the rule requires leaks monitoring twice a year. Compressor stations -- generally large facilities encompassing numerous pieces of equipment that operate continuously and under significant pressure -- must conduct quarterly leaks monitoring. Owners and operators at all sites will have one year to conduct an initial leaks monitoring survey.
  - *Allows an alternative approach for finding leaks*. In addition to optical gas imaging (special cameras that allow the user to "see" leaks), the final rule allows owners/operators to use "Method 21" with a repair threshold of 500 ppm as an alternative for finding and repairing leaks. Method 21 is an EPA method for determining VOC emissions from process equipment. The method is based on using a portable VOC monitoring instrument, such as an organic vapor analyzer (sometimes referred to as a "sniffer").
  - *Offers owners/operators the opportunity to use emerging, innovative technologies to monitor leaks.* The final rule outlines the type of information owners/operators would need to submit to receive approval to use those technologies to meet their leaks monitoring requirements.
  - *Phases in requirements for using a process known as a "green completion" to capture emissions from hydraulically fractured oil wells*. Owners/operators will have six months from the time the final rule is published in the Federal Register to meet the green completion requirements. Owners/operators of hydraulically fractured oil wells will be required to reduce emissions using combustion controls until the green completion requirement takes effect.
- Before issuing the proposed regulations in 2015, EPA sought input from states, tribes, industry and environmental groups, and continued to do so as it developed the final rules. The agency received more than 900,000 public comments on the proposed NSPS and held three public hearings.

- A number of states regulate, or are considering regulating, air pollution from the oil and natural gas industry, and EPA's rules allow them to continue to do so. Under the Clean Air Act, states have the authority to regulate air emissions from sources within their boundaries, provided their requirements are at least as protective as federal requirements. The final rule provides a pathway for companies to harmonize the NSPS with any comparable state requirements they may have.

- The final NSPS is expected to reduce 510,000 short tons of methane in 2025, the equivalent of reducing 11 million metric tons of carbon dioxide. Natural gas that is recovered as a result of the rule can be used as a fuel on site or sold.
- EPA estimates the final rule will yield climate benefits of $690 million in 2025 (2012$), which will outweigh estimated costs of $530 million. Net climate benefits are estimated at $170 million in 2025.
- The rule also is expected to reduce other pollutants, including 210,000 tons of VOCs and 3,900 tons of air toxics in 2025. These reductions also are expected to yield benefits; however, EPA was not able to quantify those. Those benefits include reductions in health effects related to fine particle pollution, ozone and air toxics, along with improvements in visibility.

Collecting Information to Develop Regulations for Existing Sources

- EPA issued the first draft of an Information Collection Request (ICR), seeking a broad range of information on the oil and gas industry, including: how equipment and emissions controls are, or can be, configured; what installing those controls entails; and the associated costs. This includes information on natural gas venting that occurs as part of existing process or maintenance activities, such as well and pipeline blowdowns, equipment malfunctions and flashing emissions from storage tanks. Industry will be legally required to respond to the final ICR.
- EPA announced its plans to issue the ICR on March 10, 2016, as part of a joint commitment between the U.S. and Canadian governments to take new actions to reduce methane pollution from the oil and gas sector, including through regulations for existing sources. The ICR is the first step in that process; the information companies will report to EPA will provide the foundation necessary for developing comprehensive regulations to reduce emissions from existing oil and gas sources.
- Over the past year, substantial amounts of new information on methane emissions from the oil and gas industry have become available from a range of entities, including EPA's Greenhouse Gas Reporting Program, industry organizations, and research studies by government, academic and industry researchers. That information shows that methane emissions from this large and complex industry are much higher than previously understood.
- The information EPA receives through the ICR will help the agency determine how to best reduce emissions from existing sources. It will help EPA identify sources with high emissions and the factors that contribute to those emissions. And it will build on information that states with regulatory programs have already developed about this industry.

- In addition, because technology to detect, measure and mitigate methane emissions is rapidly developing, EPA plans to issue a voluntary Request for Information, inviting oil and gas owners and operators, along with states, nongovernmental organizations, academic experts and others, to provide information on innovative strategies to accurately and cost-effectively locate, measure and mitigate methane emissions. EPA will issue the Request for Information soon.

- For more details on the draft ICR and the comment process, see https://www3.epa.gov/airquality/oilandgas/methane.html

Clarifying and Implementing Permitting Requirements

- EPA issued two rules to clarify permitting requirements for the oil and natural gas industry: the Source Determination Rule, and a final federal implementation plan to implement the Minor New Source Review Program in Indian country.

Final Source Determination Rule

  - EPA has issued a final rule to clarify when multiple pieces of equipment and activities in the oil and gas industry must be deemed a single source when determining whether major source permitting programs apply. The programs are the Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review preconstruction permitting programs, and the Title V Operating permits program.

  - The final rule defines the term "adjacent" to clarify that equipment and activities in the oil and gas sector that are under common control will be considered part of the same source if they are located near each other – specifically, if they are located on the same site, or on sites that share equipment and are within ¼ mile of each other. Input from states, industry and other commenters was helpful in finalizing these requirements.

  - The final rule applies to equipment and activities used for onshore oil and natural gas production, and for natural gas processing. It does not apply to offshore operations.

  - For more information on the final Source Determination Rule, including a fact sheet on the rule, see https://www3.epa.gov/airquality/oilandgas/actions.html.

Final Federal Implementation Plan for Indian Country

  - EPA also has issued a final rule to implement the Minor New Source Review Program in Indian country for oil and natural gas production. Known as a Federal Implementation Plan, or FIP, the rule will limit emissions of harmful air pollution while making the preconstruction permitting process more streamlined and efficient for this industry, which has expanded rapidly in some areas of Indian country.

  - The FIP will be used instead of site-specific minor New Source Review (NSR) preconstruction permits in Indian country and incorporates emissions limits and other requirements from eight federal air standards -- including the final NSPS -- to ensure air quality is protected.

- o The final FIP applies throughout Indian country, except non-reservation areas, unless a tribe or EPA demonstrates jurisdiction for those areas.
- o Requirements of the FIP apply to all new and modified true minor sources in the production segment of the industry that are seeking minor NSR permits in areas designated as attainment or unclassifiable for a National Ambient Air Quality Standard. Sources locating in nonattainment areas will need to seek site-specific minor NSR permits, or comply with reservation-specific FIPs, where those exist.
- o For more information on the final FIP, including a fact sheet on the rule, see https://www3.epa.gov/airquality/oilandgas/actions.html .

For More Information

- To read the final rules, including additional fact sheets, visit https://www3.epa.gov/airquality/oilandgas/actions.html .
- To read the draft Information Collection Request notice, along with additional information, visit https://www3.epa.gov/airquality/oilandgas/methane.html .
- To learn more about the Natural Gas STAR: Methane Challenge Program, see https://www3.epa.gov/gasstar/methanechallenge/
- To read the Climate Action Plan: Strategy to Reduce Methane Emissions, see: https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf

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Methane Emissions from Abandoned Oil and Gas Wells in California

Eric D. Lebel*, Harmony S. Lu, Lisa Vielstädte, Mary Kang, Peter Banner, Marc L. Fischer, and Robert B. Jackson

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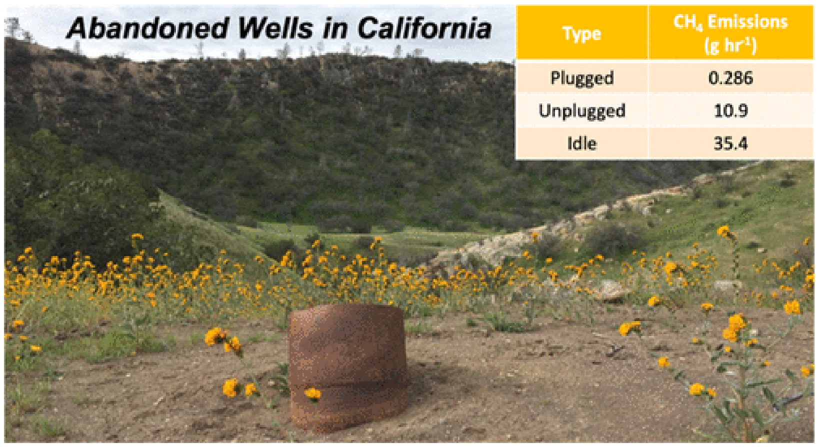
SUBJECTS: Biological databases, Computer simulations, Fluxes, Hydrocarbons, Lipids

Abstract



California hosts ~124,000 abandoned and plugged (AP) oil and gas wells, ~38,000 idle wells, and ~63,000 active wells, whose methane (CH_4) emissions remain largely unquantified at levels below ~2 kg CH_4 h^{-1}. We sampled 121 wells using two methods: a rapid mobile plume integration method (detection ~0.5 g CH_4 h^{-1}) and a more sensitive static flux chamber (detection ~1×10^{-6} g CH_4 h^{-1}). We measured small but detectable methane emissions from 34 of 97 AP wells (mean emission: 0.286 g CH_4 h^{-1}). In contrast, we found emissions from 11 of 17 idle wells—which are not currently producing (mean: 35.4 g CH_4 h^{-1})—4 of 6 active wells (mean: 189.7 g CH_4 h^{-1}), and one unplugged well—an open casing with no infrastructure present (10.9 g CH_4 h^{-1}). Our results support previous findings that emissions from plugged wells are low but are more substantial from idle wells. In addition, our smaller sample of active wells suggests that their reported emissions are consistent with previous studies and deserve further attention. Due to limited access, we could not measure wells in most major active oil and gas fields in California; therefore, we recommend additional data collection from all types of wells but especially active and idle wells.

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.0c05279.

- Additional details about the methodology, including the geomagnetic surveys, chambers, mobile plume integrator; analyzers used; and description of the tar pit in Los Angeles County (PDF)
- Spreadsheet containing specific emissions measurements for individual wells measured in this study (XLSX)

» es0c05279_si_001.pdf (878.53 kb)
» es0c05279_si_002.xlsx (33.42 kb)

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INSIDE

PETROLEUM NEWS

REFINING NEWS

- **PBF Torrance**: On January 20, an emergency flaring event took place.
- **Valero Wilmington**: On January 25 through February 1, the refinery experienced flaring due to planned maintenance.
- **Chevron El Segundo**: On January 30, an emergency flaring event took place.
- **Chevron Richmond**: On February 10, a flaring event took place due to a process upset in one of the units, prompting precautionary evacuations of less than 100 people.

GASOLINE RETAIL PRICES BY BRAND

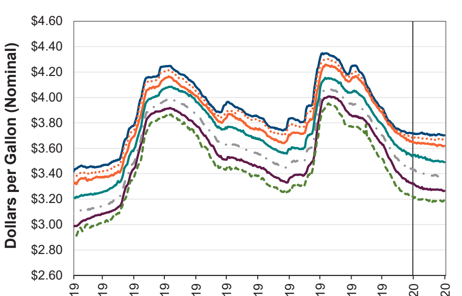
January 2020 vs. 2019

(Percentage Change)

76	8% higher
ARCO	8% higher
Chevron	7% higher
Hypermart	8% higher
Shell	8% higher
Unbranded	8% higher
Valero	8% higher

January 2020 Averages

76	$3.63
ARCO	$3.28
Chevron	$3.71
Hypermart	$3.19
Shell	$3.68
Unbranded	$3.40
Valero	$3.51



Source: California Energy Commission (CEC) analysis of Oil Price Information Service (OPIS) data

DIESEL RETAIL PRICES BY REGION

January 2020 vs. 2019

(Percentage Change)

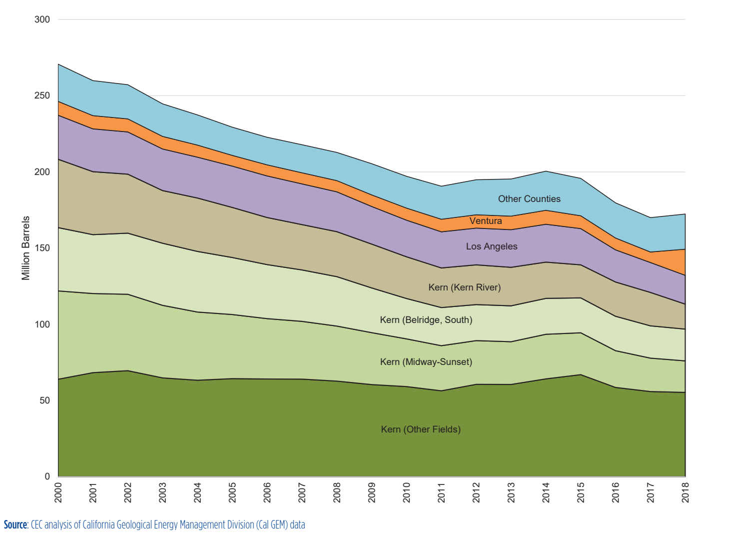
Northern CA	3% higher
Central CA	2% lower
Southern CA	3% higher

January 2020 Averages

Northern CA	$3.77
Central CA	$3.67
Southern CA	$3.88

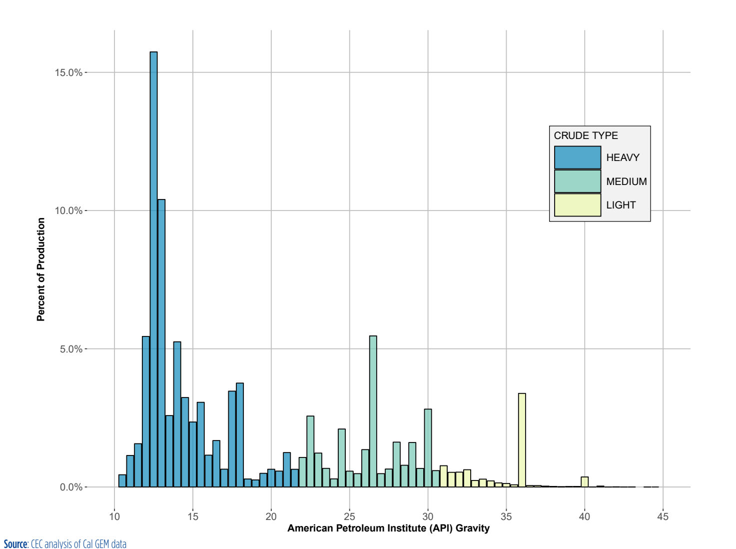
Source: CEC analysis of OPIS data

CALIFORNIA OIL FIELD PRODUCTION



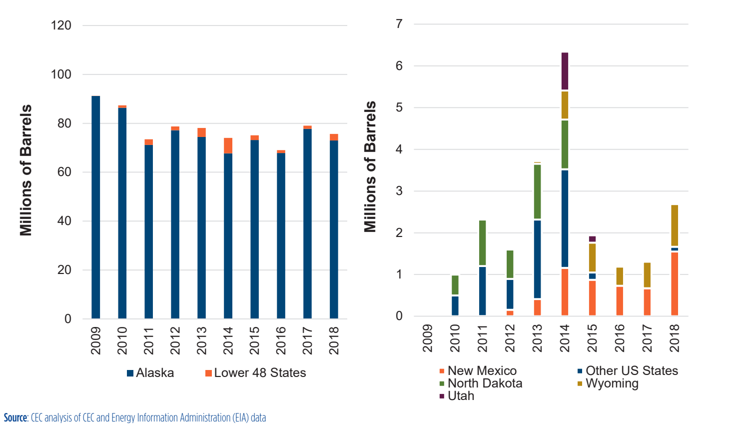
Source: CEC analysis of California Geological Energy Management Division (Cal GEM) data

CALIFORNIA OIL FIELD API GRAVITY IN 2018



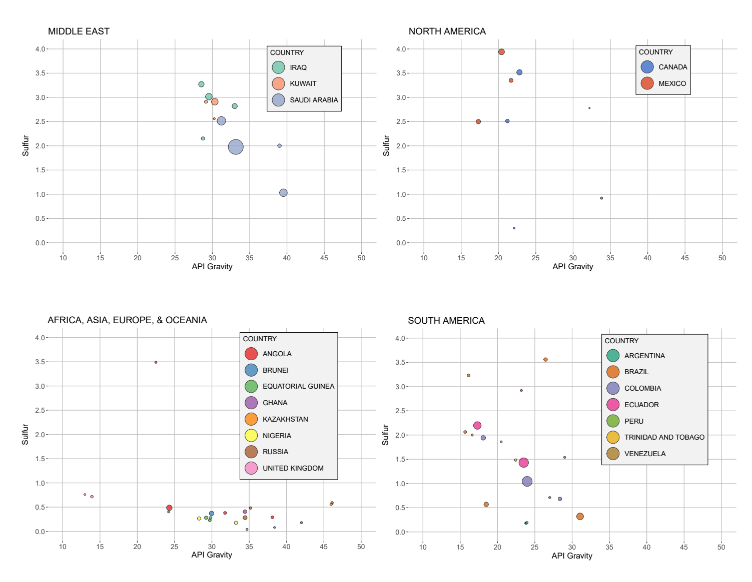
Source: CEC analysis of Cal GEM data

OIL FROM THE U.S. TO CALIFORNIA



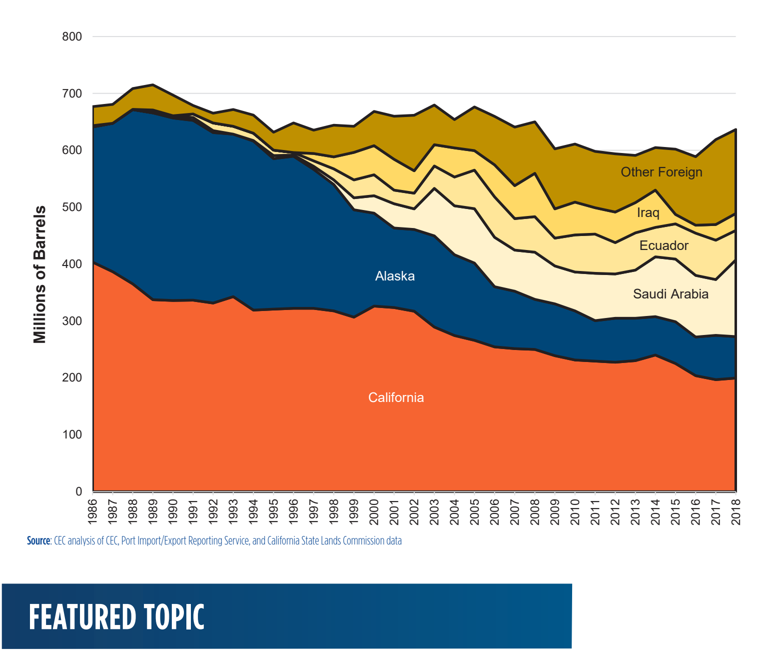
Source: CEC analysis of CEC and Energy Information Administration (EIA) data

PROPERTIES OF OIL FROM OTHER COUNTRIES TO CALIFORNIA



Source: CEC analysis of EIA data

SOURCES OF OIL TO CALIFORNIA



Source: CEC analysis of CEC, Port Import/Export Reporting Service, and California State Lands Commission data

FEATURED TOPIC

WHAT TYPES OF CRUDE OIL DO CALIFORNIA REFINERIES PROCESS?

WHAT IS CRUDE OIL?

Crude oil, or petroleum, is composed of hydrocarbons and other organic materials found in the Earth's crust. Crude oil is refined primarily to provide energy through transportation fuels, such as gasoline and diesel, and to produce petrochemicals used to create products such as plastics and pharmaceuticals. The chemical makeup of crude oil varies depending on the location of extraction. The petroleum industry measures the quality of crude oil using the following properties: specific gravity, sulfur content, acid content, nitrogen, viscosity, pour point, mercaptan, hydrogen sulfide, metals, and organic chlorides.[1]

The most widely reported crude properties are specific gravity and sulfur content. Specific gravity measures the density of a substance compared to water. The petroleum industry uses the American Petroleum Institute (API) gravity scale, which sets the density of water at 10 degrees. A refinery will use API gravity to categorize crude oil as light (more than 31.1 degrees), medium (22.3 to 31.1 degrees), heavy (10 to less than 22.3 degrees), or extra heavy (less than 10 degrees).[2] Crude that is on the heavier, more viscous side of the API gravity scale is denser. Extracting a heavy crude (with for example an API gravity of 12) from the ground is like trying to drink a milkshake through a thin straw.

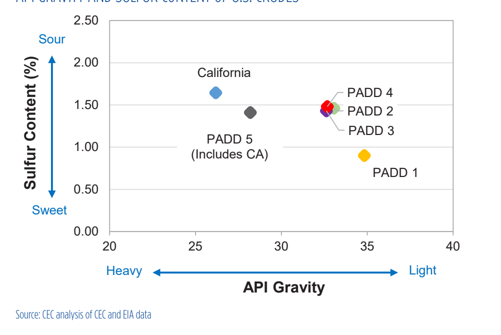
Sulfur content of crude oil is measured by the percentage of sulfur within crude. Higher sulfur content in crude oil is undesirable because transportation fuels have a sulfur content limit due to the formation of harmful sulfur oxides when sulfur burns. Also, because sulfur is corrosive, crude oil that has high sulfur content is more damaging to refinery equipment and pipelines. Crude oil is considered sweet if sulfur content is 0.5 percent or less, and sour if sulfur content is more than 0.5 percent.[3]

The properties of crude oil are used to help determine its market value. Crude oil that is light and sweet is usually more expensive than crude that is heavy and sour. A reason for this is that light sweet crudes are less energy-intensive to refine than heavy sour crude. Refiners mix many types of crude oil from both foreign and domestic sources to achieve their desired crude profile.

WHAT KIND OF CRUDE OIL GOES INTO CALIFORNIA REFINERIES?

Refiners work towards processing crudes with similar properties because a significant shift to a lighter

API GRAVITY AND SULFUR CONTENT OF U.S. CRUDES



Source: CEC analysis of CEC and EIA data

or heavier crude oil would require major changes to the refinery. To get their desired crude type, refiners may mix many types of crude, like light and heavy crudes; or they may mix only a few types, like medium crudes. Deciding which crudes to mix depends on factors like price, availability, and refinery maintenance.

The API Gravity and Sulfur Content of U.S. Crudes chart displays properties of crudes used by California refineries compared to the properties of crudes used in other Petroleum Administration for Defense Districts (PADDs). PADDs are geographic aggregations: PADD 1 is the East Coast, PADD 2 is the Midwest, PADD 3 is the Gulf Coast, PADD 4 is the Rocky Mountains, and PADD 5 is the West Coast. On average, California crude inputs are heavier and sourer than inputs in the rest of the United States. In 2018, crude inputs to California refineries had an average API gravity of 26.18 and an average sulfur content of 1.64 percent.

SOURCES OF CRUDE OIL TO CALIFORNIA REFINERIES

In 2018, California refineries received 31.1 percent of their crude from California, 11.4 percent from Alaska, and 57.5 percent from foreign sources. Sources of Oil to California displays the top suppliers of crude. The top three foreign sources are Saudi Arabia, Ecuador, and Iraq. Foreign sources of crude are increasing because California and Alaska oil fields are aging. As the oil fields become older and depleted, extracting crude oil becomes more difficult. Foreign imports supplement declining domestic sources.

CALIFORNIA'S CRUDE OIL

California crude oil production in 2018 breaks down into the following API gravity categories: 68 percent of crude oil is heavy, 24 percent is medium, and the remaining 8 percent is light. California Oil Field API Gravity in 2018 shows the distribution of API gravity for California crudes.

California Oil Field Production breaks down production by county and region. Kern County produces the most in California, with 65.7 percent of total oil in 2018 originating from Kern oil fields. The top three producing oil fields in Kern County are Midway-Sunset (12 percent), Belridge-South (12 percent), and Kern River (9.5 percent). Together, the three fields extract about as much oil as the rest of the producing counties combined.

CRUDE OIL FROM THE REST OF THE UNITED STATES

The largest supplier of Oil from the U.S to California refineries is Alaska. Imports from Alaska vastly outweigh imports from the lower 48 states. The other largest suppliers of oil to California are New Mexico, North Dakota, Utah, and Wyoming. The 2018 API Gravity of U.S. Crudes fall within the light crude category.

2018 API GRAVITY OF U.S. CRUDES

State	Average API
Alaska	32
New Mexico	43
North Dakota	44
Utah	39
Wyoming	39.5

Source: CEC analysis of CEC and ExxonMobil data

CRUDE OIL FROM OTHER COUNTRIES

There are many reasons why California refineries import different types of crude oil, but all are rooted in meeting refinery needs. Properties of Oil from Other Countries to California shows the major crude supplying countries by color and import volumes are represented by the size of the circle. In 2018, California refineries imported foreign oil from three major regions: Middle East, South America, and North America. The largest supplier of light crude to California is Saudi Arabia, with 134.8 million barrels. Other large suppliers from the Middle East are Iraq (29.8 million barrels) and Kuwait (22.5 million barrels), which are also light crude sources. All crude oil coming out of the Middle East is sour, having a sulfur content greater than 0.5 percent.

As production in California oil fields has declined, California refineries have filled their need for heavy crude oil by increasing imports from South America. The largest supplier of crude oil from the region is Ecuador (51.8 million barrels), primarily supplying heavy crude. The next largest supplier is Colombia with an API gravity of 18 to 28 degrees. Brazil is the final major supplier in the region, providing 17.6 million barrels as two distinct crudes, a heavy crude (15 to 18 API) and a medium crude (26 to 31 API). Crude from North America consists of small quantities from Canada (10.9 million barrels) and Mexico (15 million barrels) with the majority of crude oil being heavy and with sulfur content around 2 percent. Refiners source the remaining crude from Africa, Asia, Europe, and Oceania, which ranges in crude properties.

1 McKinsey Energy Insights, Qualities (crude) https://www.mckinseyenergyinsights.com/resources/refinery-reference-desk/qualities-crude
2 API Gravity http://www.petroleum.co.uk/api
3 Sweet vs. Sour Crude Oil http://www.petroleum.co.uk/sweet-vs-sour

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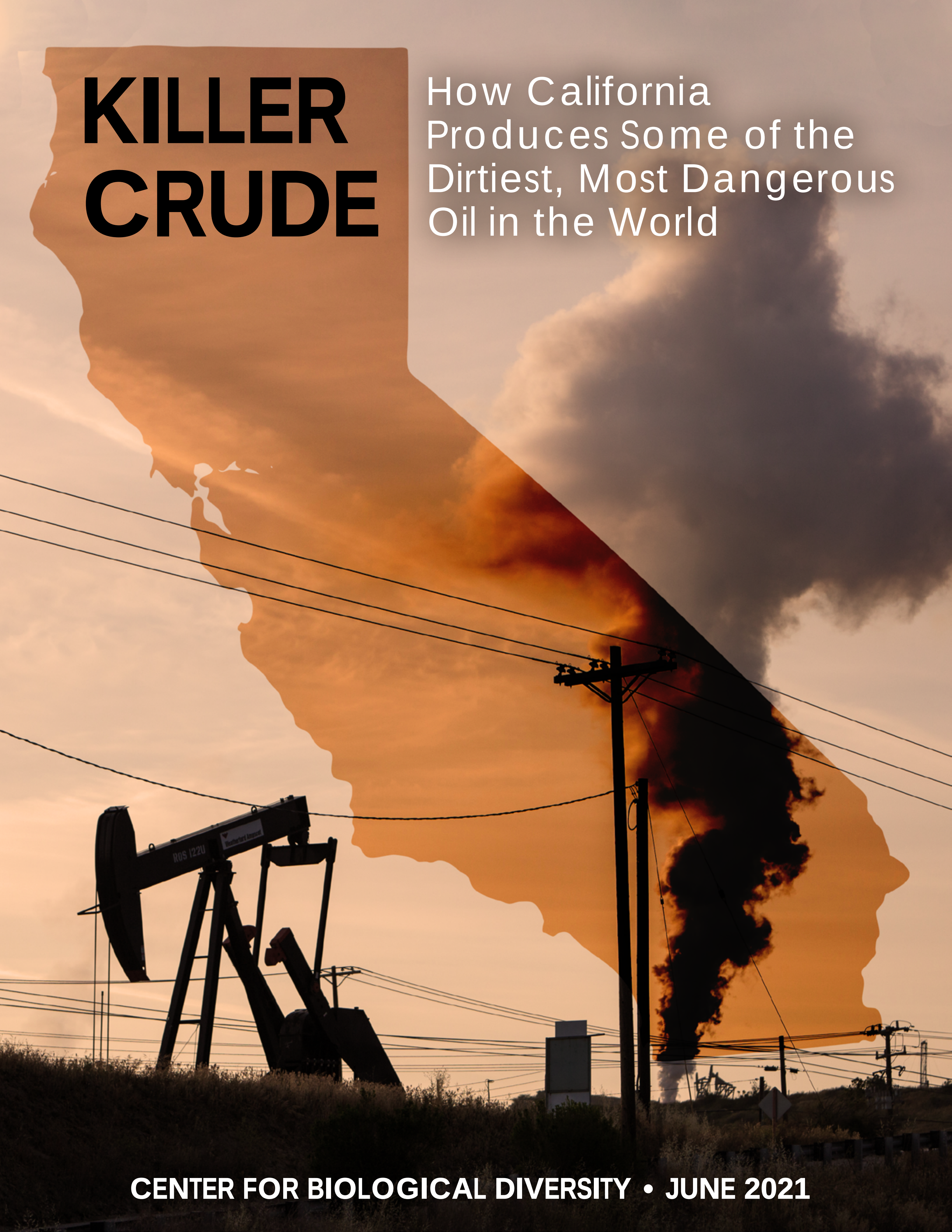

KILLER CRUDE

How California Produces Some of the Dirtiest, Most Dangerous Oil in the World

CENTER FOR BIOLOGICAL DIVERSITY • JUNE 2021

KILLER CRUDE: HOW CALIFORNIA PRODUCES SOME OF THE DIRTIEST, MOST DANGEROUS OIL IN THE WORLD

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Cover photo by Drew Bird Photography

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Executive Summary

Despite California's reputation as a global climate leader, California-sourced oils are now among the most climate-damaging in the world and are rapidly becoming even more so. This report analyzes the state's oil production and refining to show the dramatic increase in California oil's carbon intensity over roughly the past decade. It finds that California-sourced oils have gone from bad to worse and are now dirtier than oils refined here from other states and global regions including the Middle East, South America, Africa, Canada and Mexico.

California has a huge impact as the nation's seventh-largest producer of crude oil and the third-largest oil refiner. In 2020 California oil companies produced more than 144 million barrels of crude oil, and state regulators issued more than 1,900 permits for new oil wells. This takes our state in the wrong direction at a critical juncture, as the scientific consensus tells us that we must phase out fossil fuel extraction to keep global heating below 1.5 degrees Celsius and prevent climate catastrophe.

Our findings on the worsening carbon intensity of California oil give state leaders an even greater opportunity — and responsibility — to confront ongoing health harms, climate damage and environmental racism by ending new oil and gas approvals and immediately banning fracking in the state. In April 2021 Gov. Gavin Newsom ordered state regulators to ban fracking by 2024 and study the phaseout of California oil production by 2045, but the climate and health crises demand action now, not decades in the future.

We studied upstream carbon intensity values (from exploration to refinery gate) provided by the California Air Resources Board for all oils refined in California. We found that the average carbon intensity of all oil refined in California is increasing, but the average carbon intensity of just the oil produced in California is increasing far faster. The carbon intensity of California-sourced oil is growing at twice the rate of all oils refined in California, and nearly three times the rate of oils produced outside of California (Figure E1). By 2019 the average carbon intensity of California-sourced crudes was more than one-and-a-half times greater than that of crudes produced outside of California.

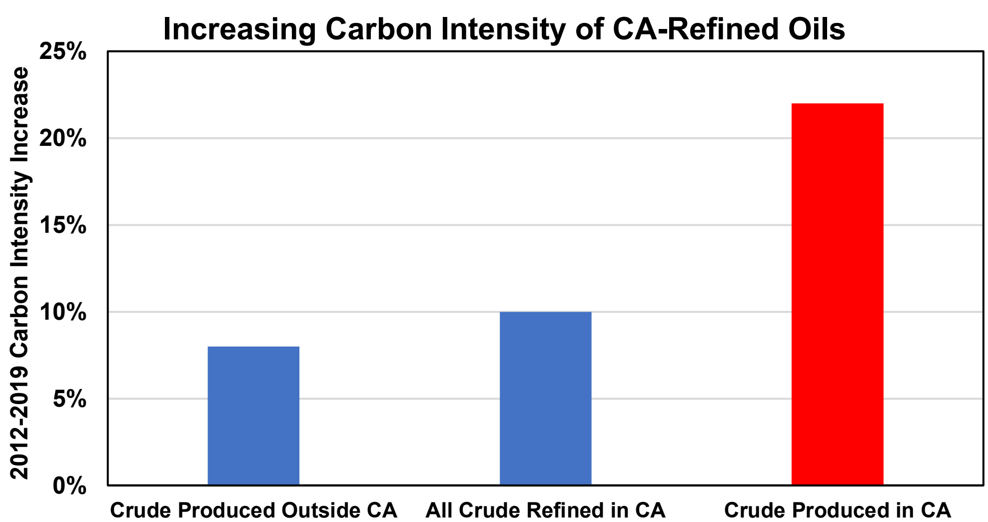

Figure E1: Increase in average carbon intensity between 2012 and 2019 for: (1) crude produced outside CA; (2) all crude refined in CA; (3) crude produced in CA.

Further evidence of California-sourced oil's outsized carbon footprint can be found in its contribution to the average carbon intensity of California-refined oil. California oil was 31% of all oil refined in California between 2012 and 2019 but was responsible for 39% of upstream carbon emissions.

Thus, on average, California oil emits more carbon dioxide per barrel than the rest of the global supply refined in California. So, although California oil production is declining, the increase in carbon intensity is helping to cancel out the climate benefits of declining production.

We also found that oil produced and refined in California is more climate-damaging than the notoriously dirty Canadian tar sands crude refined here. In 2019 the average upstream carbon intensity of California-sourced oil exceeded that of Canadian tar sands crude refined in California, with 98 kg CO_2eq/barrel for California oil and 90 kg CO_2eq/barrel for Canadian tar sands crude.

To avoid the worst dangers of climate change, the world must transition away from fossil fuels. No jurisdiction is better suited than California to lead the way in phasing out dirty oil and gas production. For California this means an end to approvals for new oil and gas wells and an immediate ban on fracking and related extreme techniques that only amplify the damage from extraction.

While a full phaseout of in-state production will take some time, it needs to be much faster than Gov. Newsom's 2045 target. A health-and-safety buffer should also be implemented immediately to prevent oil and gas drilling in communities and to protect public health and safety from air pollution and other harms of oil and gas extraction. Without taking these steps, California cannot protect the climate or the state's most vulnerable communities.

San Ardo Oil Field by Loco Steve/Flickr

Introduction: California's Oil Production Undermines Its Climate, Environmental Justice and Public Health Goals

Despite California's image as a leader on climate and the environment, the state's oil industry contributes heavily to dangerous climate-heating pollution. California is the nation's seventh-largest producer of crude oil and the third-largest oil refiner.[1] In 2020, California oil companies produced more than 144 million barrels of crude oil, while Gov. Newsom's state regulators issued more than 1,900 permits for new oil wells.[2] The flood of permits for new oil wells runs directly counter to the imperative to phase out fossil fuel extraction to prevent the worst climate damages. It also perpetuates the environmental justice and health crises caused by oil and gas extraction in California.

Overwhelming scientific consensus has shown that without deep and rapid emissions reductions, global warming will exceed 1.5 degrees Celsius compared to preindustrial levels, resulting in catastrophic damage around the world.[3] Every fraction of additional warming above 1.5 degrees will worsen these harms, threatening lives, livelihoods, the environment and global security for this and future generations. Because 75% of global greenhouse gas emissions and 85% of U.S. emissions come from fossil fuels,[4] phasing out fossil fuel extraction and combustion is of urgent necessity to avert climate catastrophe.

Unfortunately, today the world faces a fossil fuel "production gap" of tremendous proportions: Producers currently plan to extract far more fossil fuels than a livable planet will allow.[5] There is enough oil, gas and coal in already developed fields and mines globally — that is, places where the infrastructure is built and the capital is sunk — to far exceed the carbon budget for 1.5 degrees C if these reserves were all produced and burned.[6] This means that meeting global climate goals requires an immediate halt to the approval of new fossil fuel projects and a phaseout of existing oil, gas and coal extraction *before* the reserves in existing fields and mines are fully depleted.[7]

Nowhere in the world is better suited than California, with its wealthy, diverse economy and vibrant clean energy sector, to lead the way in a rapid phaseout of oil and gas extraction. To date, however, progress has been slow and insufficient. Gov. Newsom's order for regulators to study how to phase out oil extraction by 2045 could allow another two and a half decades of toxic inaction.

To make matters worse, much of the remaining oil in California's largest oilfields is heavy and carbon intensive.[8] The "heaviness" of an oil is defined by its API gravity, which is a measure of the oil's density. A crude oil is "light" if it has an API gravity of more than 31.1 degrees, "medium" if it has an API gravity from 22.3 to 31.1 degrees, "heavy" if it has an API gravity from 10 to 22.3 degrees and "extra heavy" if under 10 degrees. In 2018, 68% of California's crude oil production was heavy.[9] Heavy oils are especially climate-damaging because they often require energy-intensive techniques such as hydraulic fracturing, waterflood, steamflood and cyclic steam to extract. This greater energy demand results in greater greenhouse gas emissions as well as greater health and safety risks.

The heaviness of oil contributes to its carbon intensity, with heavier oils tending to be more carbon intensive. Carbon intensity is a value that estimates the emissions from the production, processing and transport of crude oil. Our study of carbon intensity values for oil refined in California, provided by the California Air Resources Board, shows that California-sourced oils are especially dirty in a global context and that their carbon intensity is rapidly increasing.

Oil and gas production in California has also caused an environmental justice and public health crisis in California. Eighteen percent of the state's population lives within a mile of at least one oil or gas well. [10] The highest-density oil and gas extraction areas are predominantly located near low-income communities and communities of color.[11] These communities are disproportionately exposed to the health harms associated with oil and gas extraction such as cancer,[12] respiratory illnesses[13] and pregnancy complications. Two recent studies focused on California specifically found associations between proximity to oil and gas production and preterm birth and low birth weight.[14] A recent Harvard study found that an estimated 34,000 Californians died prematurely in one year because of fossil fuel pollution.[15]

California's failure to rein in the dirty oil extraction within its own borders, using increasingly energy-intensive and dangerous techniques, completely undermines its climate, health and justice goals.

Study Description

California refines crude oil from countries around the world, including (as of 2019) Angola, Argentina, Brazil, Canada, Colombia, Ecuador, Equatorial Guinea, Ghana, Iraq, Kuwait, Mexico, Nigeria, Oman, Peru, Russia, Saudi Arabia, Trinidad and United Arab Emirates. California also refines oil from other U.S. states including Alaska, New Mexico, North Dakota, Texas and Utah, along with oil from federal offshore sources. The remaining oil refined in California comes primarily from its own 158 major oilfields.

California's 2019 oil production was only 27% of the total 600 million barrels refined in California.[16] In 2019, 13% of the oil refined in California was from other U.S. states, predominantly Alaska, New Mexico, North Dakota, Utah and Wyoming. Notably, the oils refined from these states were all light based on API gravity.[17] Similarly, oil refined in California from the Middle East (mainly Saudi Arabia, Iraq and Kuwait), constituting 26% of oil refined in California in 2019 and the dominant foreign source, was light.[18]

The only significant foreign source of heavy oil refined in California is South America (mainly Ecuador, Colombia and Brazil), constituting 22% of oil refined in 2019.[19] Oils from Canada and Mexico, including the infamous Canadian tar sands oils, are comparable in heaviness to California oils, but as less than 5% of the total oil refined in California in 2019, they are a relatively small source.[20]

For oil refined in California, the Oil Production Greenhouse gas Emissions Estimator (OPGEE) is the model used to estimate the emissions from oil from different sources, or the carbon intensity, extending from initial oil exploration to the arrival of the oil at the refinery gate.[21]

Since 2012 the California Air Resources Board (CARB) has provided carbon intensity estimates for all oils refined in California, measured in grams CO_2 per megajoule (g/MJ — grams of CO_2eq produced per MJ of energy derived from oil).[22] The carbon intensity values are attributed to the production and transport of the crude oil supplied as petroleum feedstock to California refineries, so emissions that occur during the refining process or thereafter are not considered. Carbon intensity (CI), as a measure of greenhouse gas emissions derived from a given crude, is one way to quantify the relative harms of different crudes to the climate.

Using the carbon intensity values of the various refined oils, CARB calculates an average carbon intensity for a given year by doing a weighted average based on the volume of oil from a given source:

$$Average\ carbon\ intensity =$$

$$\frac{(Crude\ Vol.\#1 * CI\ \#1) + (Crude\ Vol.\#2 * CI\ \#2) + (Crude\ Vol.\#3 * CI\ \#3) + \cdots}{Total\ Volume\ of\ Oil\ Refined\ in\ CA}$$

where “crude vol.” is the amount of oil from a given source and “CI” is the corresponding carbon intensity of that oil.

For our study, we used the same method and CARB’s own average carbon intensity values of individual crudes to determine the average carbon intensity of different subsets of oil refined in California, including the average carbon intensity of only oils produced in California and only oils produced outside of California. The following is an example calculation of the average carbon intensity of oil from California oilfields:

$$Average\ carbon\ intensity\ of\ CA\ oil =$$

$$\frac{(Crude\ Vol.\ CA\ \#1 * CI\ CA\ \#1) + (Crude\ Vol.CA\ \#2 * CI\ CA\ \#2) + (Crude\ Vol.CA\ \#3 * CI\ CA\ \#3) + \cdots}{Total\ Volume\ of\ Oil\ Produced\ and\ Refined\ in\ CA}$$

where “crude vol. CA” is the amount of oil from a given California oilfield and “CI CA” is the corresponding carbon intensity of that oil.

Using a conversion factor of 5,813.4 MJ per barrel as an approximation,[23] all carbon intensity values in the following analysis were converted from grams CO_2 per megajoule to kilograms CO_2eq per barrel (kg CO_2eq/bbl). With carbon intensity in terms of barrels and using values for barrels of oil production, upstream emissions from oil refined in California between 2012 and 2019 were also estimated.


Oil field in Bakersfield by Babette Plana/Flickr


San Ardo Oil Field by Drew Bird Photography

Results

The carbon intensity of oil produced in California has increased 22% since 2012, increasing the overall carbon intensity of all crude refined in the state.

The average carbon intensity of all crudes refined in California has gone up 10% between 2012 and 2019, increasing from an average of 66 kg CO_2eq/barrel in 2012 to 73 kg CO_2eq/barrel in 2019. This is an increase of about 1.5% per year. Meanwhile, for just the crudes extracted from California oilfields, the average carbon intensity has gone up 22% between 2012 and 2019, increasing from 81 kg CO_2eq/barrel in 2012 to 98 kg CO_2eq/barrel in 2019. This is an increase of about 3.1% per year or double the rate of increase for the carbon intensity of all oils refined in California. For all crudes not produced in California, the average carbon intensity has gone up 8% between 2012 and 2019, increasing from 59 kg CO_2eq/barrel in 2012 to 64 kg CO_2eq/barrel in 2019. This is an increase of about 1.2% per year, or about half the increase observed for crudes produced in California (Table 1, Figure 1).

So, although the average carbon intensity of all oil refined in California is increasing, the average carbon intensity of California-produced oil is increasing far faster: twice the rate of all oils refined in California, and nearly three times the rate of oils originating outside of California. This complements an earlier estimate that the carbon intensity of California crudes on a per barrel basis increased by 39% between 2000 and 2017.[24]

Year	All Crude Refined in CA	CA-Produced Crude	Crude Produced Outside CA
2012	66.04	80.57	58.89
2013	66.10	80.63	58.72
2014	65.05	82.26	56.45
2015	70.11	86.97	61.80
2016	70.57	87.55	62.67
2017	69.35	87.72	62.32
2018	71.80	97.20	62.96
2019	72.78	98.07	63.66

Table 1: Average carbon intensity (CI) of oil refined in California between 2012 and 2019 in units of kg CO_2eq/barrel: (1) all crude refined in CA; (2) CA-produced crude; (3) crude produced outside CA.

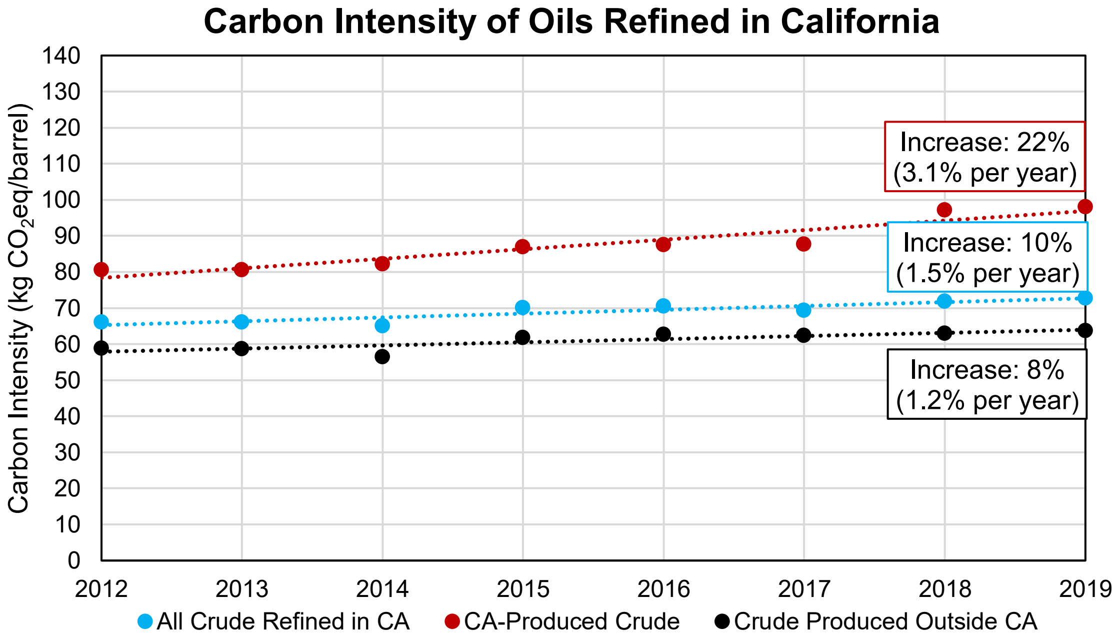

Figure 1: Increase in average carbon intensity over time for: (1) all crude refined in CA; (2) CA-produced crude; (3) crude produced outside CA.

The high carbon intensity of California-sourced oils can be traced to just a few key California oilfields.

As of 2019, California had 158 major oilfields, but five oilfields contributed more to California's average carbon intensity and upstream emissions than all others combined. These five fields in order of decreasing contribution are Midway-Sunset, South Belridge, Cymric, Kern River and San Ardo. Between 2012 and 2019, Midway-Sunset contributed 22% of the estimated upstream emissions from California-sourced oils; South Belridge contributed 12%; Cymric contributed 10%; Kern River contributed 9% and San Ardo contributed 8%. The remaining 39% was contributed by the other 153 major California oilfields (Figure 2):

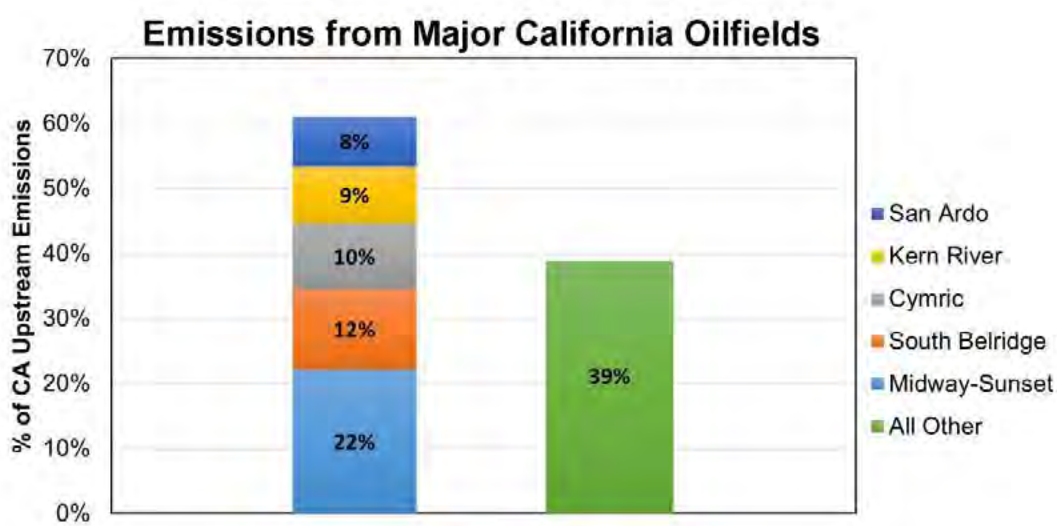

Figure 2: The top 5 California fields in terms of their contributions to the average carbon intensity and upstream emissions of California-sourced oils between 2012 and 2019. "All other" refers to all California oilfields outside of the top 5.

The contribution of specific oilfields to the average carbon intensity of California-sourced oils is strongly linked to total oil production (Figure 3), with Midway-Sunset, Kern River, South Belridge and Cymric being in the top five for contributing to California-sourced oils' average carbon intensity and the top five for California oil production. San Ardo, though in the top five for its contribution to California carbon intensity, ranks eighth in terms of oil production. The discrepancy is due to the relatively high carbon intensity of San Ardo oil.

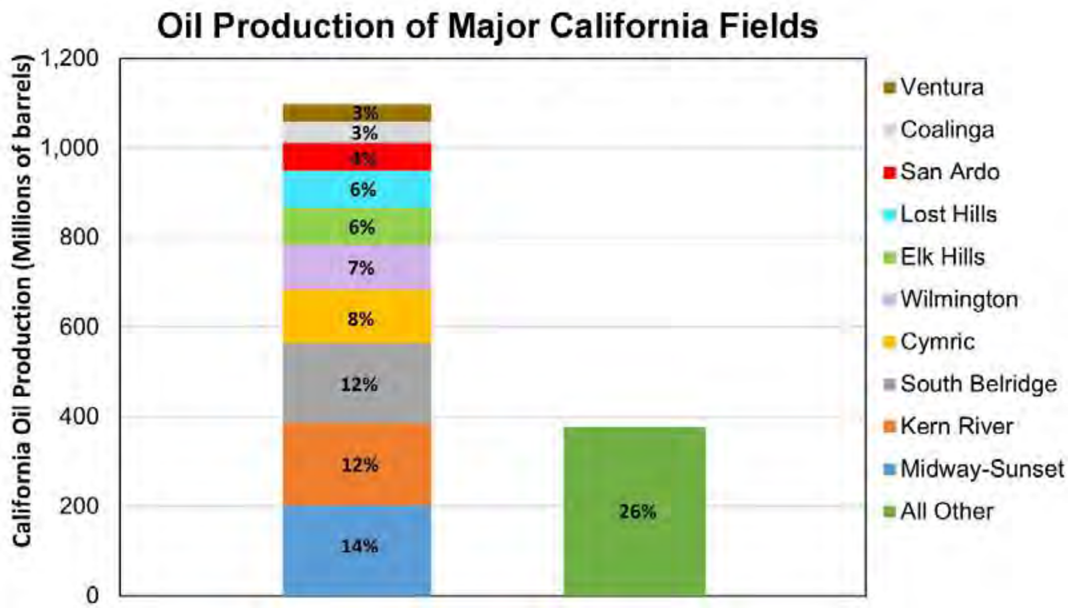

Figure 3: California's top 10 oilfields in terms of cumulative oil production between 2012 and 2019. Percent values displayed represent the percent of total California oil production. "All other" refers to all California oilfields outside of the top 10.

In terms of their contribution to the average carbon intensity of California-sourced oils, none of the top five California oilfields are in the top five for individual carbon intensity, although all are in the top 20 (Figure 4). This highlights the importance of both carbon intensity and production volume in determining the contribution of any given oilfield to the average carbon intensity and upstream emissions.

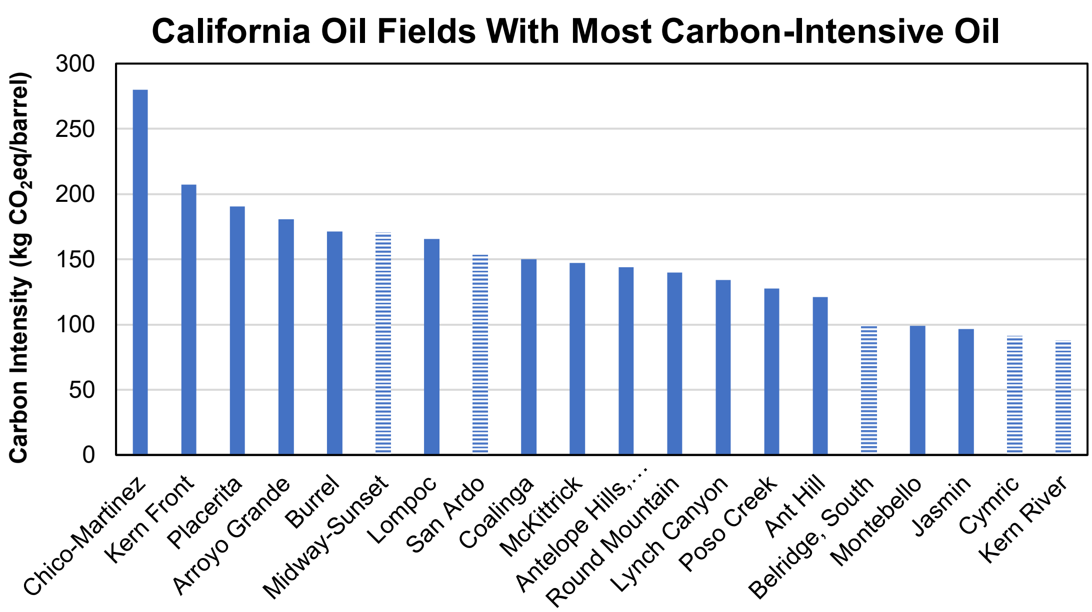

Figure 4: California's top 20 oilfields based on carbon intensity in 2019. The top 5 based on their contribution to the total upstream emissions of California-sourced oils are distinguished with horizontal stripes.

Top 10 Most Productive California Oilfields vs. Top 10 Carbon Dioxide Emitters

It's no surprise that California's top oil-producing fields also tend to contribute the most to California oil's upstream carbon dioxide emissions. Eight of the top 10 emitters are also in the top 10 for oil production. That means the fields producing the most oil also produce some of the dirtiest and most damaging crude, worsening California's overall contribution to dangerous global heating.

California oil is now more carbon intensive than notoriously dirty Canadian tar sands crude.

Our 2017 study found that three quarters of oil produced in California was as climate-damaging as Canadian tar sands crude, which is infamous for being exceptionally dirty.[25] This report shows that California oil has become more carbon intensive since that time.

In 2019 the average upstream carbon intensity of California oil exceeded that of Canadian tar sands crude with about 98 kg CO_2eq/barrel for California oil and about 90 kg CO_2eq/barrel for Canadian tar sands crude refined in California. Moreover, between 2012 and 2019, the average carbon intensity of Canadian tar sands crude refined in California declined, while the average carbon intensity of California-sourced oil increased (Figure 5). This may be due to California refineries refining proportionally less of the dirtiest Canadian oils over time.

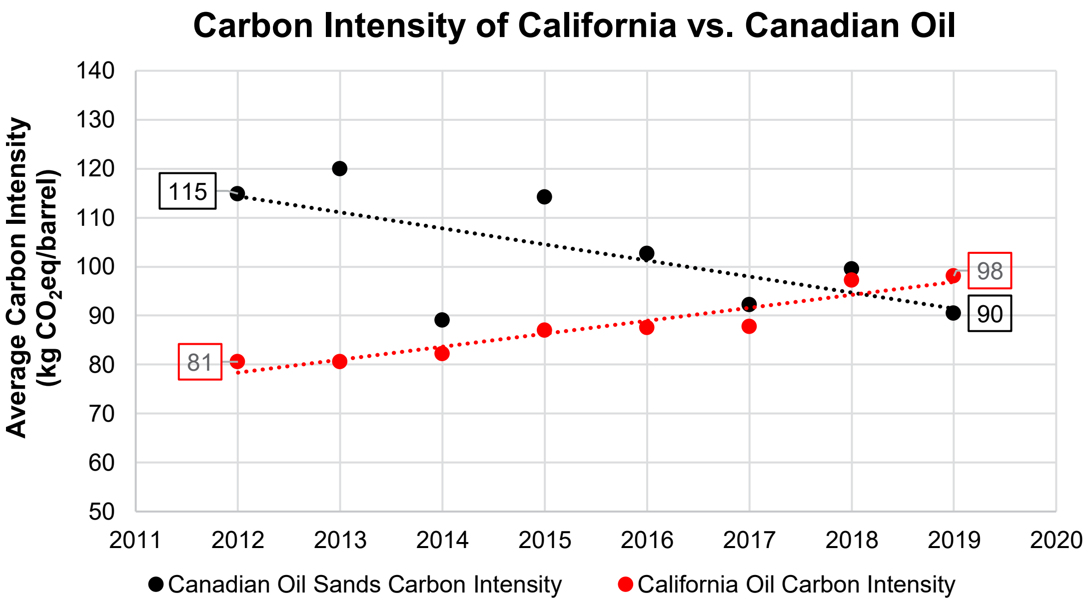

Figure 5: Change in average carbon intensity over time of Canadian oil sands crude vs. California-sourced oil. Here, average carbon intensity and average upstream emissions are interchangeable.

The last point is evidenced by the difference in the range of carbon intensities of Canadian crudes between 2012 and 2019. In 2012, the range was 44 to 142 kg CO_2eq/barrel, whereas in 2019 it was 47 to 171 kg CO_2eq/barrel. Even though the range shifted up in 2019, indicating dirtier oil streams being refined from Canada, the overall average carbon intensity was less in 2019 than in 2012, meaning a smaller proportion of these dirtier oils were refined.

Tar sands in Alberta
by Dru Oja Jay, Dominion

<u>The increase in carbon intensity of California-sourced oils is partially canceling out the benefits of the decline in California oil production.</u>

California's oil production has been in long-term decline since 1985 (Figure 6):

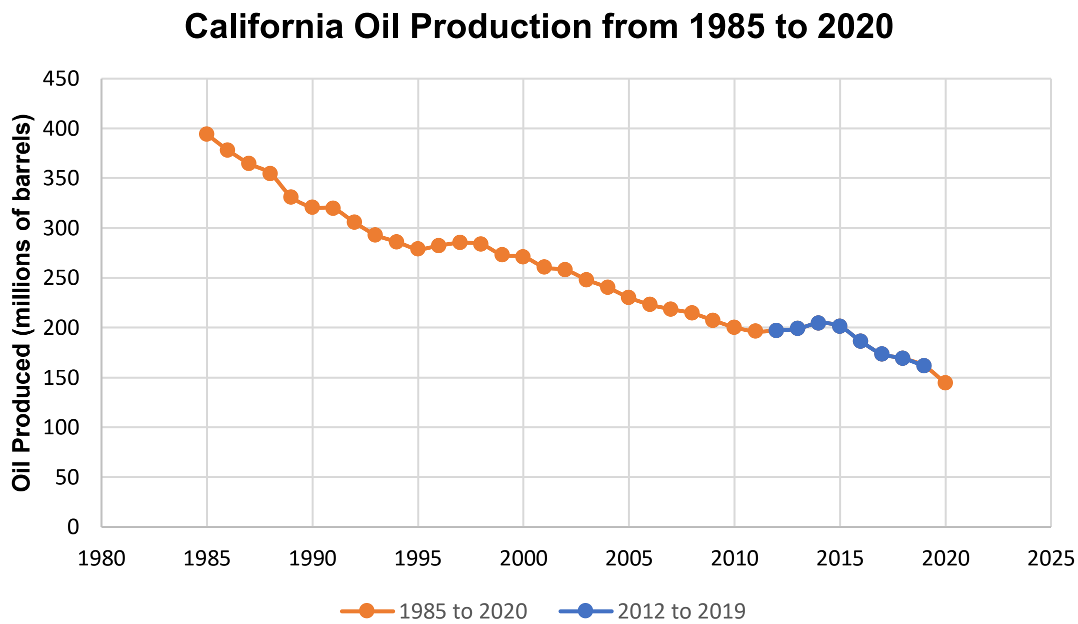

Figure 6: California oil production from 1985 to 2020.[26]

This trend holds in the 2012 to 2019 timeframe of our analysis, with the first three years holding a relatively steady annual amount of oil production, and 2015 to 2019 seeing declines in both oil production and upstream emissions from California-sourced oils (Figure 7).

However, the rate of decline in oil production from 2015 to 2019 exceeded the rate of decline in upstream emissions. While oil production declined by 22% between 2015 and 2019, upstream emissions only declined by 13%. If we compare 2012 and 2019, oil production was 20% less in 2019 than in 2012, whereas upstream emissions were only 3% less. Both cases make clear that the increase in carbon intensity of California-sourced oils is partially canceling out the climate benefits of California's oil-production decline.

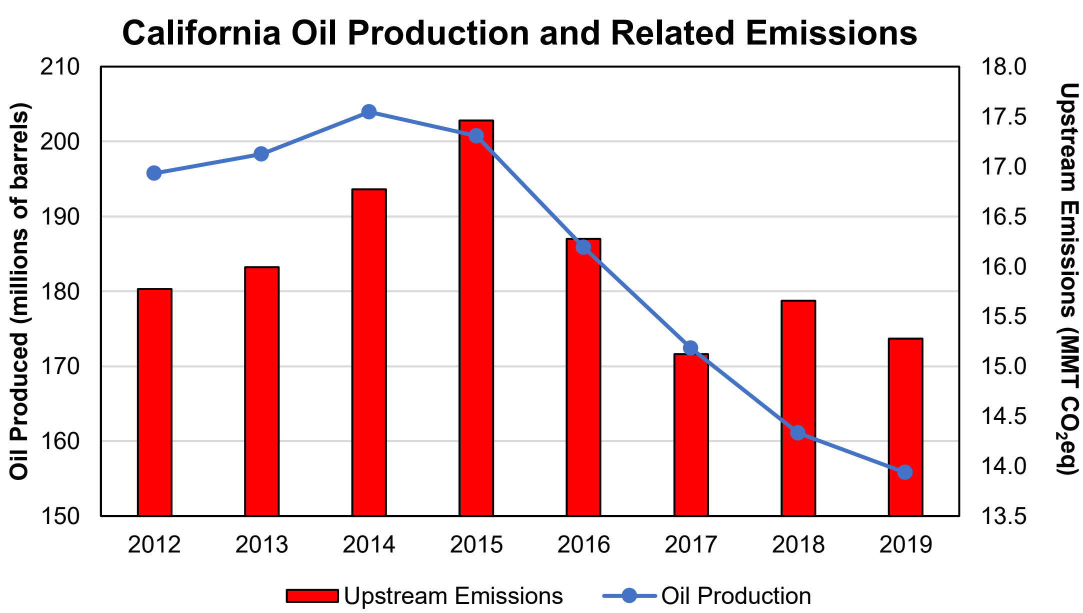

Figure 7: Upstream emissions from California-sourced oils vs. California oil production between 2012 and 2019.

For example, upstream emissions in 2015 were about 18.1 MMT CO_2eq. So if upstream emissions declined by 22% between 2015 and 2019, as oil production did, then emissions in 2019 would be about 14.1 MMT CO_2eq. Instead upstream emissions in 2019 were 15.8 MMT CO_2eq, or about 1.7 MMT CO_2eq more. Assuming this value is 20% of lifecycle emissions (upstream emissions + midstream refining emissions + downstream end use emissions; assumption addressed in more detail in the Discussion), then the lifecycle emissions would be about 8.5 MMT CO_2eq more, or an additional 2% of California's total emissions (based on a 2018 estimate of California total emissions).

Thus, increasing carbon intensity is reducing California's potential progress on reducing greenhouse gas emissions. To maximize emissions reductions, policymakers should both reduce oil production and eliminate enhanced oil-recovery techniques that increase the carbon intensity of California oils.

San Ardo Oil Field by Drew Bird Photography

Discussion

A phaseout of California oil production does not require an increase in imports.

Proponents of business-as-usual oil extraction in California often say that limiting oil production in California will require an increase in imports from parts of the world where oil is produced with fewer environmental safeguards. This is simply incorrect.

A 2018 study found that the decline in production that would result if California stopped approving new oil wells would be approximately equal to the decline in oil consumption forecast by the California Air Resources Board's (CARB's) "Scoping Plan" to reduce greenhouse gas emissions (Figure 8).[27] Ending the approval of new oil wells and accelerating the ongoing decline in the state's oil production would, therefore, not require an increase in imports.

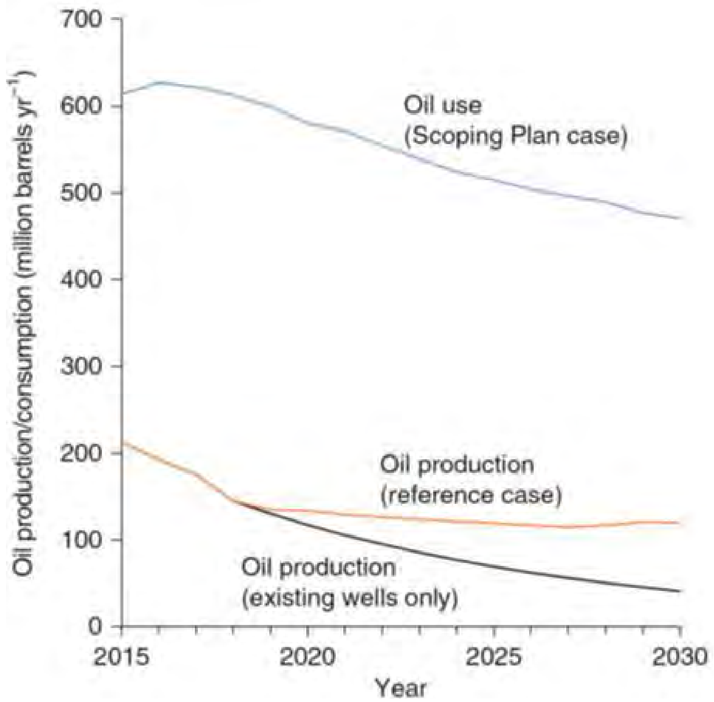

Figure 8: California's projected decline in oil production and consumption. (1) Reference scenario (orange line): developed by the U.S. Energy Information Administration, the state's annual oil production decline trajectory if it continues issuing new drilling permits; (2) No new wells (black line): production drawdown if California stopped issuing drilling permits; (3) Scoping Plan scenario (blue line): estimate of future oil use based on California's Scoping Plan (for gasoline, diesel and liquefied petroleum gas), the federal government (for residual and other oil), and the federal government and the California Energy Commission (for jet fuel). Figure and data from Erickson, P. et al. (2018).[28]

An update to the findings of the 2018 study using data from a 2020 CARB-commissioned study that charted three pathways for California carbon neutrality by 2045 strengthens this conclusion. Under CARB's "Balanced" and "Zero Carbon Energy" scenarios, the decline in California oil demand between 2020 and 2030 would exceed the decline in oil production if the state stopped issuing permits for new oil wells.[29] Thus, under California's current climate policies, California can and should simultaneously reduce in-state oil production and oil imports.

In 2020 oil production in California dropped to 144 million barrels, or by 10.6% compared to 2019.[30] According to state regulators, only 138 new wells were drilled, despite the issuance of permits for nearly 2,000 new wells.[31] Meanwhile, imports dropped by 27% from 433 million barrels to 316 million barrels.[32]

These declines are largely because of less oil consumption during the COVID-19 pandemic, but this further emphasizes the point that as California oil demand decreases, declines in production from halting new oil well permits would not need to be compensated for with increases in imports. With decreasing demand, in a no-new-permits scenario, both production and imports would decline, leading to a global decline in fossil fuel reliance.

However, research by Communities for a Better Environment reveals a troubling trend: In recent years California refineries have increased their production of gasoline for *export* to Pacific Rim countries, maintaining demand for imports despite falling oil use within the state.[33] If California allows this trend to continue, then it will continue to prop up imports. This emphasizes the need for the state to pursue a just transition that winds down all phases of the fossil fuel lifecycle, including refining.

A phaseout of oil extraction in California would not only get rid of an exceptionally dirty source of crude, but it would also lead to an overall global reduction in oil production and decrease in global carbon emissions. This is because every barrel of California oil left in the ground will reduce overall oil supply, resulting in a net decrease of about half a barrel of oil consumption globally.[34] Thus, actions taken in California to curb oil production will have global ramifications.

California's oil and gas regulatory failures have worsened the state's public health and environmental justice crises.

The oil industry's argument that production limits here will cause more production in places with weaker environmental safeguards is not only wrong, but also morally reprehensible because it minimizes California's regulatory failures and the public health and environmental justice crises caused by in-state oil production.

California's long-term regulatory failures are shocking and include the following:

- California is virtually the only major oil-producing state with no minimum setback distance between wells and homes, schools or other sensitive receptors, despite the grave health harms from oil and gas pollution.
- An EPA audit in 2011 found widespread failures in enforcing state regulations pertaining to the safety of oil and gas-related underground injection projects.[35]
- The California Geologic Energy Management Division (CalGEM) admitted in 2015 that thousands of oil and gas wells were improperly injecting wastewater into California's protected underground sources of drinking water, leading to the widespread contamination of the state's water supplies.[36] Half a decade later, the state has reneged on multiple commitments to remedy the situation and our water supplies are still being sacrificed to the oil industry.[37]
- California's lax waste-disposal laws allow oil industry wastewater to be dumped into unlined pits, which has led to multiple additional instances of groundwater contamination.[38]
- Loosening regulations on steam injection pressure led to multiple large-scale spills in Central California in 2019. CalGEM has yet to collect any fines for a 1.3-million-gallon spill in the Cymric oilfield,[39] and a separate spill of over 4 million gallons is still ongoing.[40] These spills contaminate the environment and threaten wildlife.
- Reports uncovered that multiple regulators had financial interests in oil companies,[41] and numerous top agency officials have gone on to work for the industry.
- Dozens of injection projects were approved under "dummy" files that had no underlying review for the project.[42]
- CalGEM has brought virtually no enforcement actions in response to illegal pollution.[43]
- CalGEM also has failed to comply with the environmental review and public participation requirements of the California Environmental Quality Act, despite acknowledging the environmental harms of extraction.[44]

California's regulatory record on oil and gas does not justify claims that it has the toughest environmental regulations in the world. On the contrary, it highlights the urgent need to phase out dangerous and dirty fossil fuel production in the state.

Lifecycle emissions make California oils' climate harms even more pronounced.

The carbon intensity values provided by the Air Resources Board only consider upstream emissions from oil, or the emissions from extracting and transporting oil up to the refinery gate. However, every step of the fossil fuel life cycle produces greenhouse gas pollution, including midstream refining and downstream combustion.

While we take comparisons of the upstream data from CARB as representative of the relative "dirtiness" of different oils refined in California, the overall climate impact of oils refined in California depends on the total lifecycle emissions. The emissions from midstream and downstream processes typically exceed upstream emissions. This is apparent when considering previously reported lifecycle emissions of California's top five oils in terms of upstream emissions — Midway-Sunset, South Belridge, Cymric, Kern River and San Ardo (Table 2):[45]

Field	2017 Upstream Emissions (kg CO_2eq/bbl)	2017 Lifecycle Emissions (kg CO_2eq/bbl)	% Upstream Emissions
Midway-Sunset	146	725	20%
South Belridge	86	690	12%
Cymric	112	600	19%
Kern River	56	650	9%
San Ardo	159	760	21%

Table 2: For California's top oilfields in terms of upstream emissions, listed are the upstream emissions estimates from 2017, most recent lifecycle emissions estimates from 2017, and upstream emissions per barrel as a percentage of lifecycle emissions per barrel.

Comparing the 2017 (the year with the most recent lifecycle emissions data) upstream and lifecycle emissions of the top five fields, we find that midstream and downstream processes constitute a greater proportion of emissions than upstream processes. Taking the above five fields as an example, upstream emissions are most often around 20% of the total lifecycle emissions. This agrees with an estimate by the Stockholm Environmental Institute in which factoring in upstream emissions increases the total emissions per barrel of oil by at least 25%,[46] which would likewise make upstream emissions about 20% of the total.

Putting this into perspective, California's total CO_2eq emissions across all sectors in 2018 was 425 MMT CO_2eq. In just 2018, upstream emissions from California-sourced oil were about 16 MMT CO_2eq. Assuming upstream emissions are about 20% of total lifecycle emissions, lifecycle emissions from California-sourced oil in 2018 would be about 80 MMT CO_2eq, which would make them almost 20% of California's total emissions in 2018 (Table 3).

Year	Oil Production (bbl)	Upstream Emissions (MMT CO_2eq)	Lifecycle Emissions (MMT CO_2eq)	Total CA Emissions (MMT CO_2eq)	% Upstream Emissions	% Lifecycle Emissions
2012	196	15.8	78.9	451.6	3.5%	17%
2013	198	16.0	80.0	447.6	3.6%	18%
2014	204	16.8	83.9	443.4	3.8%	19%
2015	201	17.5	87.3	440.8	4.0%	20%
2016	186	16.3	81.4	429.2	3.8%	18%
2017	172	15.1	75.6	424.5	3.6%	18%
2018	161	15.7	78.3	425.3	3.7%	18%
2019	156	15.3	76.4	--	--	--

Table 3: For the years 2012 to 2019, listed are barrels of California oil production, estimated California upstream emissions, estimated lifecycle emissions assuming upstream emissions are 20% of lifecycle emissions, and total California emissions across sectors. Using those values, upstream and lifecycle emissions as a percentage of total California emissions were calculated and listed.

The importance of considering lifecycle emissions is even more apparent when looking at the carbon intensity of California's refining itself. As follows from California both producing and accepting some of the dirtiest oil for refining, California's refining processes are exceptionally dirty.

Because California refines the heaviest crude on average, California refineries emit more CO_2eq per barrel of crude refined than those in any other major U.S. refining region. For 2013 to 2017, the average carbon intensity of California refining was 59.3 kg CO_2eq/barrel, whereas the U.S. average over the same time was 49.3 kg CO_2eq/barrel. Some individual refineries in California have refining carbon intensities as high as 79 kg CO_2eq/barrel.[47]

California-sourced oil's excessive upstream emissions burden not only California's population but the entire planet with some of the world's dirtiest refining.

California's Gas Production is More Climate-Damaging Than Coal And Threatens Public Health and Safety.

While California is the seventh-largest oil producer and third-largest oil refiner, it ranks 14th in U.S. fossil gas production, with nearly 200 billion cubic feet produced in 2019. California's gas production, however, is also exceptionally dirty, dangerous and carbon intensive.

A recent report from the California Energy Commission assumes fossil gas as part of California's energy mix well into the future, treating it as a bridge fuel. However, methane — a superpollutant 87 times more powerful than CO2 at warming the climate over a 20-year period — leaks during all phases of oil and gas production.

If the methane leakage rate is greater than 2.4% of the gas produced, then the climate damage from the methane leakage cancels out any climate benefit that gas achieves over coal at the smokestack over a 20-year period.

Therefore, depending on the overall leakage rate, fossil gas provides little or no climate benefit over coal: In fact, fossil gas may even be worse.

A recent analysis found that the methane leakage rate in the San Joaquin Valley is 4.8%, making gas sourced from this region not only worse than coal on a 20-year timescale, but also the worst in the continental United States.

In addition to its role as a major climate pollutant, gas production also threatens public health and safety. The 2015 gas leak disaster at the Aliso Canyon gas storage facility near Los Angeles resulted in 109,000 metric tons of methane entering our atmosphere—the largest-known methane release in U.S. history.

The Aliso Canyon disaster boosted statewide greenhouse gas emissions, set back emissions-reduction goals and sickened nearby residents with symptoms including dizziness, headaches, nausea, eye, nose and throat irritation, nose bleeds and likely long-term effects yet to be identified. Clearly the risks of keeping gas infrastructure in place far exceed any benefits.

Though California's dirty oil is the focus of the present study, it must be considered in the context of California's overarching dirty fossil fuel industry. The continued extraction of both exceptionally dirty oil and gas only makes a stronger case for the rapid phaseout of fossil fuels to mitigate substantial climate and public health harms.

Conclusion

Because climate change is driven primarily by fossil fuel production and combustion, most of the world's fossil fuels must stay in the ground to avoid the worst dangers of climate change. Worldwide, there are more than enough fossil fuels in already developed production fields to far exceed targets to limit warming to 1.5 degrees C or even 2 degrees C.[48] New fossil fuel development and infrastructure is thus unsafe and unjustified, and fossil fuel production must be phased out globally within the next several decades. With one of the world's wealthiest economies and some of the world's dirtiest oil, California needs to lead the way in ending fossil fuel production.

To address the climate damage, health harms and environmental injustice caused by its increasingly dirty oil production, Gov. Newsom should direct his regulators to end approvals for new oil and gas wells and other fossil fuel projects and commit to a plan to phase out existing extraction far faster than 2045. Newsom should also act now, not in 2024, to ban fracking and related extreme techniques that amplify the damage from extraction. Newsom should immediately implement a health-and-safety buffer to prevent oil and gas drilling in communities and protect public health and safety from the air pollution and other harms of oil and gas extraction. Without taking these crucial steps, California cannot protect the climate or the state's most vulnerable communities.

Inglewood Oil Field by Gary Kavanagh

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Appendix

California-sourced oil is the primary contributor to the average carbon intensity of all oil refined in California.

Although California oil was about 31% of all oil refined in California between 2012 and 2019, it was responsible for about 39% of the carbon intensity, or about 39% of the emissions leading up to the refinery gate (upstream emissions).

Calculated using the carbon intensity values provided by CARB, it is estimated that upstream emissions of oils refined in California between 2012 and 2019 were about 343 million metric tons CO_2eq (MMT CO_2eq). It follows that oil not produced in California constituted about 69% of all oil refined in California but was responsible for only 61% of the emissions leading up to the refinery gate.

As a reference, if all oils refined in California had the same carbon intensity, then their contribution to the total emissions leading up to the refinery gate would be the same as their contribution to the total volume of oil refined in California. So, a contribution to the carbon intensity that is more than the contribution to total oil refined indicates a carbon intensity above the overall average. In turn, a contribution to the carbon intensity that is less than the contribution to the total volume of oil refined indicates a carbon intensity below the overall average. This further indicates that, on average, California oil is more polluting per barrel than the rest of the global supply refined in California.

This fact holds when considering just the oil produced in the U.S. that is refined in California. Oil produced in the U.S., including oil produced in California, constitutes 46% of the oil refined in California, but 54% of the upstream emissions. However, if broken down further, oil produced in the U.S. *excluding* oil produced in California constitutes 15% of the oil refined in California but 16% of the upstream emissions.

In other words, the contribution of U.S. oil, including California, to upstream emissions is 1.2 times its contribution to the total production. The contribution of U.S. oil, excluding California, to upstream emissions is 1.05 times. And the contribution of California oil to the total upstream emissions is 1.3 times its contribution to the total production. So, normalized to production, oil produced in California contributes more to the upstream emissions for California-refined oils than other U.S. oils (Figure 9).

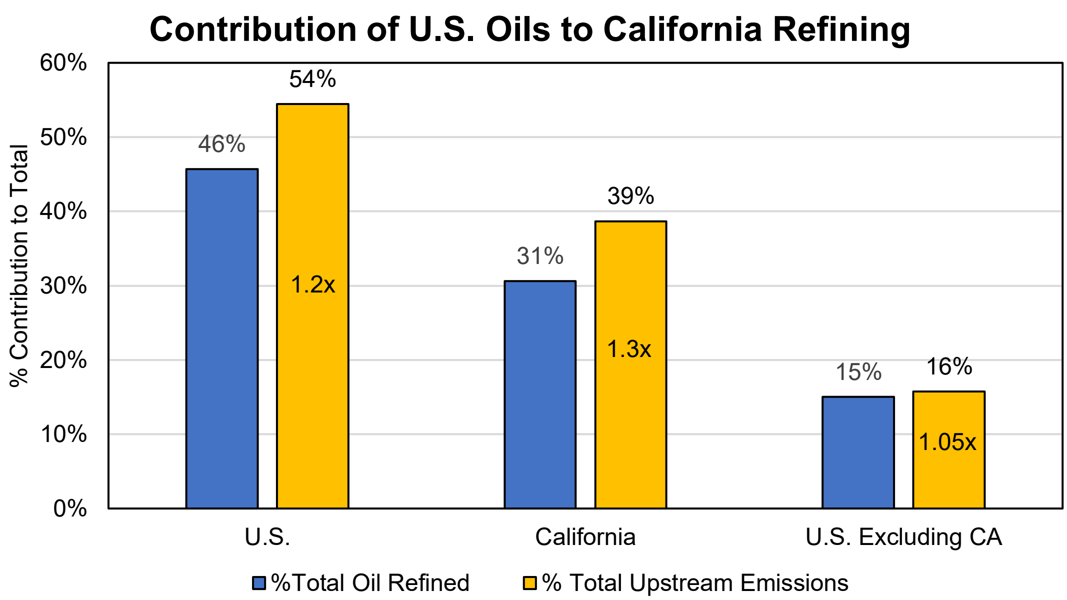


Figure 9: For U.S.-sourced oil including California, California-sourced oil, and U.S.-sourced oil excluding California, the volume of oil as a percentage of all oil refined in CA (% Total Oil Refined) vs. oil as its percent contribution to the total upstream emissions of all oil refined in CA (% Total Upstream Emissions). Also labeled on the orange bars is the multiple by which a given region's contribution to the total upstream emissions compares to its contribution to the total oil refined. Here, the contribution to average carbon intensity and the contribution to upstream emissions are interchangeable.

<u>There is strong overlap between California fields employing enhanced oil recovery techniques and those with the most upstream emissions.</u>

Enhanced oil recovery techniques such as cyclic steam and steamflooding are known to be energy-intensive compared to conventional oil extraction with the result being greater associated greenhouse gas emissions. In California, 19 fields have cyclic steam wells (Figure 10) while 18 fields have steamflood wells (Figure 11), with significant overlap of the two groups.

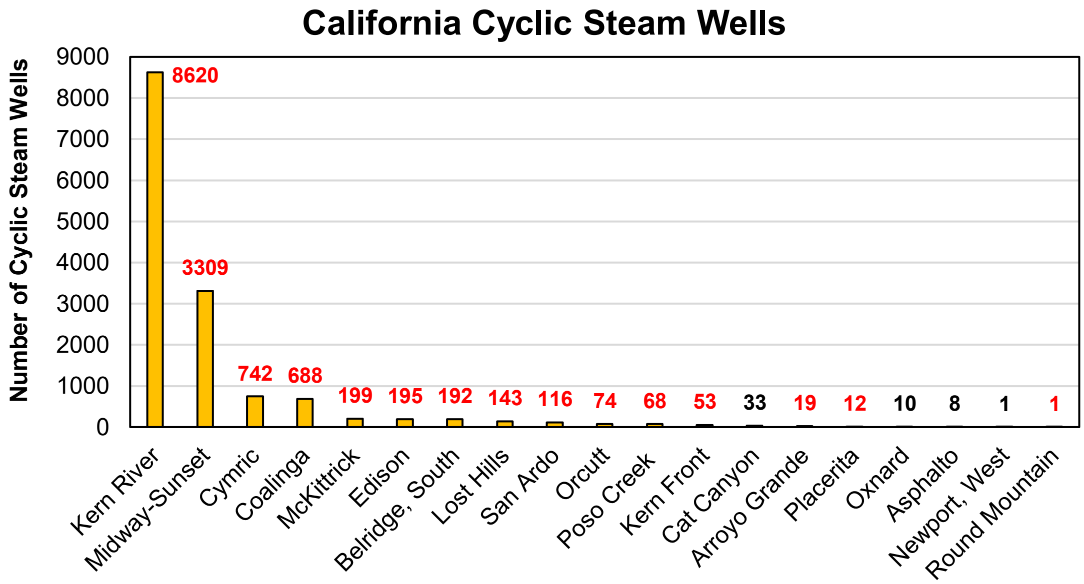


Figure 10: Cyclic steam wells in California based on 2020 data. The number of cyclic steam wells in each oilfield is labeled. The oilfields that are also in the top 20 for upstream emissions have red labels.

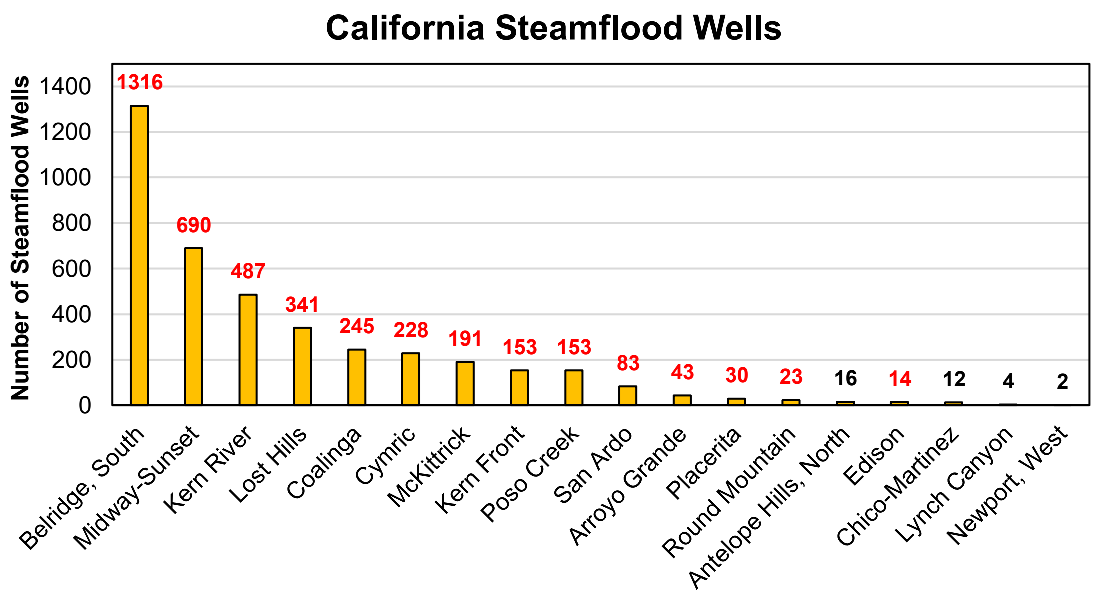


Figure 11: Steamflood wells in California based on 2020 data. The number of steamflood wells in each oilfield is labeled. The oilfields that are also in the top 20 for upstream emissions have red labels.

Notably, of the 19 oilfields with cyclic steam wells, 15 rank in the top 20 for their contribution to upstream emissions from California-sourced oils. Of the 18 oilfields with steamflood wells, 14 rank in the top 20 for their contribution to upstream emissions. Also, four of the top five oilfields in terms of upstream emissions rank highly in terms of numbers of steam wells: Kern River, Midway-Sunset, and Cymric are 1, 2, and 3, respectively, for number of cyclic steam wells while South Belridge, Midway-Sunset, and Kern River are 1, 2, and 3, respectively, for number of steamflood wells. The top five oilfields for upstream emissions (the four mentioned, plus San Ardo) together have 70% of California's steamflood wells and 90% of California's cyclic steam wells, or 85% of California's total steam wells (cyclic steam + steamflood).

<u>There is significant overlap in California between fracking permits, enhanced oil recovery and the most carbon-intensive oil extraction.</u>

In 2020, 1,929 oil and gas drilling permits were issued in California with 1,052 of them, or 55%, going to the top five fields contributing the most to greenhouse gas emissions. Of the top five fields, South Belridge received the most with 351, then Midway-Sunset with 346, Cymric with 221, Kern River with 111 and San Ardo with 23.

Of the total permits, 1,359 were for oilfields in the top 20 for carbon intensity (Figure 6).

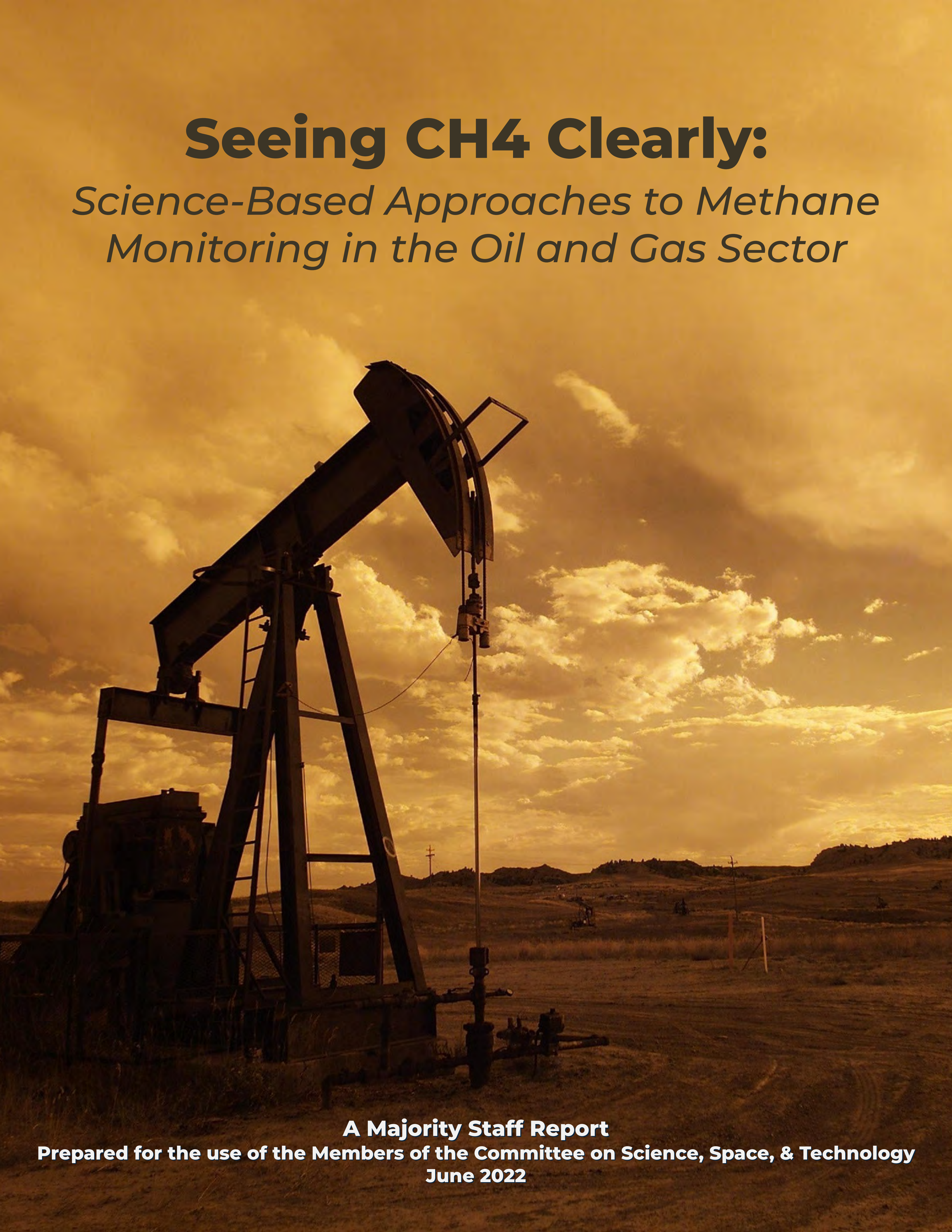
Finally, of the total permits, 65 were for cyclic steam wells and 64 were for steamflood wells. Out of the 129 total cyclic steam and steamflood well permits, 78 permits, or 60%, were for fields in the top five for greenhouse gas emissions.

In 2020, 84 permits for fracking were issued with 24, or 29%, for South Belridge. Another 36, or 43%, were issued for Lost Hills Oil Field. Lost Hills has not been previously mentioned, but it is noteworthy as number seven in terms of oilfield greenhouse gas emissions. The remaining permits were granted to North Belridge which is number 22 in terms of oilfield greenhouse gas emissions.

As is the case with existing enhanced oil recovery wells, the oilfields being granted oil and gas drilling and fracking permits are those that already contribute the most to California oil's greenhouse gas emissions, hence maintaining a vicious cycle.

Seeing CH4 Clearly:

Science-Based Approaches to Methane Monitoring in the Oil and Gas Sector



A Majority Staff Report

Prepared for the use of the Members of the Committee on Science, Space, & Technology

June 2022

Committee Jurisdiction

Under House Rule X, the Committee on Science, Space, and Technology has oversight jurisdiction over "laws, programs, and Government activities relating to nonmilitary research and development." Additionally, the Committee possesses legislative jurisdiction over "All energy research, development, and demonstration;" "Environmental research and development;" and "Scientific research, development, and demonstration." The Committee staff's perspective and recommendations are guided by these jurisdictional parameters, as well as the Committee's priorities and longstanding interest in promoting scientific efforts to combat climate change.

House Rule X is available at https://rules.house.gov/sites/democrats.rules.house.gov/files/117-House-Rules-Clerk.pdf.

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Executive Summary

In early 2021, the Committee on Science, Space, and Technology initiated an investigation into methane leaks and strategies for detecting them in the oil and gas sector. The purpose of the investigation was to inform the role of the Federal research and development enterprise in reducing and quantifying methane emissions.

Committee staff conclude that oil and gas companies are failing to design, equip, and inform their Methane Leak Detection and Repair (LDAR) activities as necessary to achieve rapid and large-scale reductions in methane emissions from their operations. The sector's approach does not reflect the latest scientific evidence on methane leaks. Oil and gas companies must change course quickly if the United States is to reach its methane reduction targets by the end of this decade.

The Committee staff's key findings can be summarized as follows:

I. **Oil and gas companies are failing to address super-emitting leaks.** Recent scientific research has established that a small group of massive, "super-emitting" methane leaks is disproportionately responsible for methane emissions from the oil and gas sector. But today's operator-led LDAR programs lack the capability to effectively mitigate methane emissions from super-emitters. They do not define the size of a super-emitting leak, identify and track super-emitting leaks when they occur, assess how much super-emitting leaks contribute to their overall methane emissions, or use observations on super-emitters to inform their approach to leak detection in the future. By not prioritizing methane super-emitters, oil and gas companies are missing opportunities for rapid emissions reductions.

II. **Oil and gas companies are failing to use quantification data to mitigate methane leak emissions.** Commercially available LDAR technologies are capable of quantifying the size of methane leaks from oil and gas operations, and oil and gas companies have performed extensive pilots of these technologies in the Permian Basin. While today's technologies possess certain limitations, the data they provide is already accurate and precise enough to help oil and gas companies that are seeking to reduce methane leaks, better understand their methane emissions profiles, and measure their progress. But oil and gas companies largely are not incorporating methane quantification data into their LDAR programs for operational and analytical purposes.

III. **Oil and gas companies are deploying innovative LDAR technologies in a limited and inconsistent manner.** Oil and gas companies can realize sweeping methane mitigation benefits by deploying innovative LDAR technologies comprehensively across their operations. While many oil and gas companies are deploying these technologies at varying scales and frequencies, most deployments remain in the pilot phase with scopes that are too narrow to support emissions reductions on a timeline that meets the urgency of the climate crisis.

The Committee staff also learned that oil and gas companies have internal data showing that methane emission rates from the sector are likely significantly higher than official data reported to EPA would indicate. A very significant proportion of methane emissions appear to be caused by a small number of super-emitting leaks. One company experienced a single leak that may be equivalent to more than 80% of all the methane emissions it reported to EPA – according to EPA's prescribed methodology – for all of its Permian oil and gas production activities in 2020.

The Committee staff recommend that the Federal government:

1. Create a new Federal program to conduct accurate methane measurement surveys – a Methane Census – over major oil and gas basins in the United States on a regular basis, and consider how the data from these surveys can be assessed alongside existing methane inventory data
2. Help develop voluntary, consensus technical standards to assist oil and gas sector stakeholders in using quantification data to estimate aggregate methane emissions
3. Create a new Federal program to strengthen methane detection capabilities and reduce measurement uncertainty
4. Develop consensus best practices for oil and gas companies to use when evaluating the adoption and implementation of innovative LDAR technologies
5. Create a Methane Emissions Measurement and Mitigation Research Consortium to encourage research partnerships and information sharing between industry, academia, non-profit organizations, and other stakeholders in the oil and gas sector
6. Commission a report from the National Academies of Sciences, Engineering, and Medicine to articulate a science-based strategy for the use of greenhouse gas detection and monitoring capabilities at Federal agencies to detect methane emission events, including super-emitters
7. Ensure that Federal regulations to control methane from the oil and gas sector enable technology diversity and scientific innovation in LDAR technologies

Oil and gas companies possess the following opportunities to address methane leaks:

1. Join the United Nations Environment Programme's Oil and Gas Methane Partnership 2.0 Framework
2. Accelerate the comprehensive deployment of innovative LDAR technologies
3. Adopt science-based LDAR strategies to maximize methane emissions reductions from oil and gas operations as rapidly as possible

Investigation Scope and Objectives

This report assesses whether additional Federal research programs and investments are required to achieve large-scale reductions in methane emissions from the oil and gas sector, consistent with America's methane reduction targets for the next decade and beyond.

Permian Basin

The Committee chose to focus its oversight on operators in the Permian Basin due to the centrality of that region as a source of oil and gas sector methane emissions. The Permian, which extends across 55 counties amidst a vast expanse in West Texas and Southeast New Mexico, accounted for 42.6% of U.S. oil production and 16.7% of U.S. natural gas production in December 2021.[1] Methane emissions resulting from oil and gas production are correspondingly large: a recent scientific study concluded that "the Permian Basin is likely the largest observed methane-emitting [oil and gas] basin in the United States."[2]

Innovative Leak Detection and Repair Technologies

A major objective of the Committee's investigation was to understand the capabilities and limitations of innovative Leak Detection and Repair (LDAR) technologies so that capability gaps and opportunities for Federal research investment could be identified. Innovative LDAR technologies have the potential to accelerate methane emissions reductions from the oil and gas sector and serve as an indispensable tool for the detection and quantification of methane leaks. However, as a general principle, Committee staff do not express a preference regarding the merits of one type of deployment method relative to another or endorse the capabilities of any specific vendor's technology relative to their competitors. This report does not identify specific innovative LDAR companies, but rather discusses innovative LDAR technologies according to their method of deployment, which allows for useful generalizations.

EPA Rulemaking

In November 2021, the EPA issued a proposed rule to directly regulate methane emissions from existing sources in the oil and gas sector for the first time, as well as strengthen the emission reduction requirements that already exist for methane emissions from new and modified sources.[3] This rulemaking reflects a clear need for robust Federal regulations to ensure that the oil and gas industry moves swiftly towards large-scale reductions in methane emissions from its operations. These forthcoming regulations will be an essential pillar of America's drive to achieve the targets set forth in the Global Methane Pledge.

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[1] Federal Reserve Bank of Dallas. "Permian Basin." *Energy in the Eleventh District*, 13 May 2022, accessed here: https://www.dallasfed.org/research/energy11/permian.aspx#Region.

[2] Zhang, Yu Zhong, et al. "Quantifying methane emissions from the largest oil-producing basin in the United States from space." *Science Advances*, vol. 6, issue 17, 22 April 2020, accessed here: https://doi.org/10.1126/sciadv.aaz5120.

[3] Environmental Protection Agency. "EPA Proposes New Source Performance Standards Updates, Emissions Guidelines to Reduce Methane and Other Harmful Pollution from the Oil and Natural Gas Industry." 2 Nov. 2021, accessed here: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-proposes-new-source-performance.

We note, however, that the substance of the EPA's rulemaking is not the subject of this report. While there is considerable overlap between the policy matters that the Committee seeks to assess and some of the technical questions that the EPA confronts in its rulemaking, the Committee's focus lies squarely with Federal scientific research and the role that Federal research programs and investments can play in promoting methane emissions reductions from the U.S. oil and gas sector. The Committee staff's findings, and the subsequent policy recommendations that are derived from them, are rooted in the Committee's legislative and oversight jurisdictions.

Investigation Methodology

Committee staff undertook a broad review of the oil and gas sector's current practices related to methane leak detection and repair, methane leak emissions, and the use of innovative LDAR capabilities. This section describes the definitions, methods, assumptions, and sources of information used to inform our review.

Committee Outreach

Over the course of an 18-month investigation, the Committee staff consulted extensively with a broad range of experts and stakeholders to ensure that our understanding of the issues was comprehensive, consistent with the latest scientific data, and reflective of current practices. We engaged in discussions with academic experts, scientific researchers, not-for-profit organizations, innovative LDAR vendors, industry trade associations, and oil and gas companies. These discussions provided invaluable insights into the challenges that confront efforts to detect, quantify, and reduce oil and gas sector methane leaks, as well as the areas that would benefit from Federal research investment and support. We thank all of the experts and stakeholders that helped inform the development of this report through their expertise, their experience, and their perspectives.

As a part of its investigation, the Committee also requested information directly from oil and gas companies pertaining to their methane leak detection and repair programs, methane leak emissions, and use of innovative leak detection and repair technologies. On December 2, 2021, Chairwoman Johnson sent letters to ten operators in the Permian Basin.[4] Each letter contained an Information Request consisting of a series of questions and document requests. Chairwoman Johnson sent letters to the following operators:

- Admiral Permian Resources Operating, LLC
- Ameredev II, LLC
- Chevron Corporation
- ConocoPhillips
- Coterra Energy Inc.
- Devon Energy Corporation
- ExxonMobil Corporation
- Mewbourne Oil Company
- Occidental Petroleum Corporation
- Pioneer Natural Resources Company

The Committee identified the ten operators based upon a holistic review of several factors, including their level of production in the Permian, their reported methane emissions for 2020 under the EPA's Greenhouse Gas Reporting Program (GHGRP), and the size and frequency of the methane leaks detected within their operations by aerial surveys conducted in 2020 through

[4] House of Representatives Committee on Science, Space, and Technology. "Letters to Permian Basin Oil and Gas Companies Seeking Methane Leak Emission Data", 2 Dec. 2021, archived here: https://science.house.gov/letters-to-permian-basin-oil-and-gas-companies-seeking-methane-emission-data.

the Environmental Defense Fund's PermianMAP project.[5] These factors were designed to ensure that the Committee's review would encompass the largest producers in the Permian while also creating a representative cross-sample of the Permian oil and gas sector, including companies of different sizes, companies both publicly-traded and privately-held, and companies that have recently expanded the scope of their Permian operations as well as traditional producers.

By the end of January 2022, all ten operators had provided initial narrative responses to Chairwoman Johnson's letter. Between February and May 2022, the Committee staff engaged in a series of follow-up meetings with a number of the operators to discuss their responses in greater detail. The operators also provided additional documents and records during this period that were responsive to Chairwoman Johnson's request. The Committee staff appreciate the willingness of these ten companies to engage with the Committee and to provide detailed information regarding their perspectives on methane leaks, their leak detection and repair practices, and their evaluation and deployment of innovative leak detection and repair technologies. In the end, the Committee staff reviewed over 500 pages of relevant documents. We consider all ten operators to have been appropriately responsive to Chairwoman Johnson's letter and Information Request.

Definitions

The definition of a "methane leak" and the defined scope of "leak detection and repair" activities are the subject of ongoing debate. Throughout its investigation, the Committee defined these terms broadly:

- **Methane Leak:** Any release of methane that results from a malfunction or an abnormal operating condition, including both unintentional [i.e., fugitive] emissions and emissions resulting from malfunctions or abnormal operating conditions among vented sources and combustion sources.
- **Leak Detection and Repair (LDAR) Program:** Any program or activity that is intended to monitor, detect, or repair methane leaks, or monitor, detect, quantify, or mitigate methane emissions resulting from methane leaks, including through the implementation of operational changes.

The Committee also employed a simple definition to differentiate between "innovative" and "traditional" LDAR technologies:

- **Innovative LDAR Technology**: Any instrument-based LDAR technique that is not currently approved for purposes of regulatory compliance under the applicable EPA regulations (40 CFR part 60, subpart OOOOa).[6] The definition essentially considers all LDAR technologies other than the two techniques currently approved by EPA – the use of OGI cameras or Method 21 – to be innovative for purposes of this analysis.

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[5] Environmental Protectional Agency. "Greenhouse Gas Reporting Program." 2020, accessed here: https://www.epa.gov/ghgreporting; Environmental Defense Fund. "Permian Methane Analysis Project." 2022, accessed here: https://permianmap.org/.
[6] 40 CFR § 60.OOOOa, accessed here: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOa.

Oil and gas sector LDAR technologies are extremely diverse from a technological perspective. They extend from traditional optical gas imaging (OGI) cameras to innovative LDAR technologies, which include novel ground-based, drone-based, aircraft-based, and satellite-based methane sensor systems, as well as accompanying data analytics platforms that process methane detection data.[7] Many innovative LDAR technologies are systems comprised of multiple novel components, including the sensors that detect methane emissions, the deployment methods that support the sensors, and the data analytics platforms that use defined parameters, assumptions, data inputs, and models to quantify emission rates. We use the term “innovative LDAR technologies” throughout this report to capture both individual technologies and the complex systems within which they operate for methane leak detection and repair.

[7] See EPA’s August 2021 Methane Detection Technology Virtual Workshop for examples of innovative LDAR technologies. Environmental Protection Agency. “EPA Methane Detection Technology Workshop.” 23-24 Aug. 2021, accessed here: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.

Scientific Overview: Methane and the Oil and Gas Sector

The Committee staff's approach throughout this investigation has been guided by the best available science regarding oil and gas sector methane emissions. A central question is whether the sector's approach to methane leaks is similarly rooted in scientific fact.

Methane and Climate Change

Methane (CH_4) is the second-largest contributor to atmospheric warming since the beginning of the industrial era, trailing only carbon dioxide and accounting for approximately 30% of global warming since the Industrial Revolution.[8] Methane is a short-lived climate pollutant with an atmospheric lifetime lasting only about a decade. However, for the duration of its lifetime, methane is a far more potent greenhouse gas than carbon dioxide, with a global warming potential that is 84-87 times greater than CO_2 over a 20-year timeframe and 28-36 times greater than CO_2 over a 100-year timeframe.[9] Methane's short but extremely powerful atmospheric lifetime carries significant policy implications. Immediate action to reduce atmospheric concentrations of methane would rapidly reduce the rate of overall atmospheric warming, providing a unique opportunity to slow the pace of climate change, prevent the advent of devastating climate-related feedback loops, and gain additional time to achieve further long-term greenhouse gas emissions reductions.[10] In its most recent report, the Intergovernmental Panel on Climate Change asserted that in order to limit global warming to the crucial target of 1.5℃, methane emissions must be reduced by one third.[11]

Unfortunately, the past decade witnessed a substantial increase in atmospheric methane levels, culminating in the highest annual growth rate for methane on record in 2021.[12] Building upon the scientific consensus regarding methane's crucial role as an accelerant of climate change, the international community has increasingly identified methane mitigation as a central element of the global strategy to combat climate change. In November 2021, at the 26th UN Climate Change Conference of the Parties in Glasgow, Scotland, the United States and the European Union led more than 100 countries in formally launching the Global Methane Pledge, a multinational

[8] United Nations Environment Programme and Climate and Clean Air Coalition. "Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions." *United Nations Environment Programme*, 2021, accessed here: https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions; International Energy Agency. "Global Methane Tracker 2022." *IEA*, February 2022, accessed here: https://www.iea.org/reports/global-methane-tracker-2022.

[9] International Energy Agency. "Methane Tracker 2021." *IEA*, January 2021, accessed here: https://www.iea.org/reports/methane-tracker-2021.

[10] United Nations Environment Programme and Climate and Clean Air Coalition. "Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions." *United Nations Environment Programme*, 2021, accessed here: https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions.

[11] Intergovernmental Panel on Climate Change. "Climate Change 2022: Impacts, Adaptation, and Vulnerability." *Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, 2022, accessed here: https://www.ipcc.ch/report/ar6/wg2/.

[12] National Oceanic and Atmospheric Administration. "Increase in atmospheric methane set another record during 2021." 7 April 2022, accessed here: https://www.noaa.gov/news-release/increase-in-atmospheric-methane-set-another-record-during-2021.

commitment to reduce global methane emissions 30% below 2020 levels by 2030.[13] If the Global Methane Pledge's targets are achieved, humanity can prevent 0.2 degrees Celsius of warming by 2050, a crucial step towards the larger goal of avoiding the worst impacts of climate change.[14] Thus, for the next decade and beyond, the effort to cut methane emissions will be a pivotal part of the fight against climate change.

Oil and Gas as a Source of Methane Emissions

In the United States, the rapid and large-scale reductions in methane emissions that are necessary to meet the goals of the Global Methane Pledge cannot be achieved without addressing methane emissions from the oil and gas sector. The energy sector represents the second largest source of anthropogenic methane globally, and the oil and gas sector is the largest global energy-based methane emitter, responsible for nearly 70% of all fossil fuel-related methane emissions through extraction, processing and distribution.[15] Similar trends exist in the United States. Oil and gas sector operations are the second-largest source of anthropogenic methane emissions in the U.S., responsible for an estimated 30% of all methane released due to human activities domestically.[16] Since the U.S. is one of a group of eight countries that are estimated to emit nearly half of all global methane emissions, domestic oil and gas operations make a significant contribution to rising atmospheric methane levels globally.[17]

Yet even while continuing to emit methane at a disturbing pace, the U.S. oil and gas sector holds great promise as a part of the country's methane mitigation strategy. Indeed, compared to the other large domestic sources of methane – agriculture and landfills – oil and gas operations offer the most straightforward path to the kind of rapid emissions reductions that are required to reach America's 2030 commitments.[18] This can be explained primarily by two factors: cost-effectiveness and technological feasibility.

Methane is the main component of natural gas. Natural gas accounts for about a quarter of global electricity generation, and in 2020 – despite the global pandemic – the United States alone consumed 30.5 trillion cubic feet of natural gas.[19][20] Thus, methane is distinguished as a formidable climate pollutant when released into the atmosphere, but a valuable commodity when gathered and stored properly. As such, investments that reduce methane losses in the oil and gas

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[13] Climate and Clean Air Coalition. "Global Methane Pledge." 2022, accessed here: https://www.globalmethanepledge.org/
[14] *Id*.
[15] United Nations Environment Programme and Climate and Clean Air Coalition. "Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions." *United Nations Environment Programme*, 2021, accessed here: https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions.
[16] Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks." 14 April 2022, accessed here: https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.
[17] *Id*.
[18] Environmental Protection Agency. "Overview of Greenhouse Gases." 16 May 2022, accessed here: https://www.epa.gov/ghgemissions/overview-greenhouse-gases.
[19] Energy Information Administration. "Natural gas explained." 24 May 2022, accessed here: https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.
[20] Energy Information Administration. "In 2020, U.S. natural gas prices were the lowest in decades." *Today in Energy*, 7 January 2021, accessed here: https://www.eia.gov/todayinenergy/detail.php?id=46376.

sector supply chain are revenue generators. One recent research study reviewed a range of economically and technically feasible methane mitigation strategies by sector and concluded that "the majority of economically feasible actions come from the oil and gas sector… oil and gas measures dominate the [potential] avoided warming from economically feasible actions."[21] The International Energy Agency (IEA) asserts that a significant percentage of methane emission reductions from the oil and gas sector would, in fact, impose no cost upon the sector at all due to the market value of the secured natural gas.[22]

Furthermore, it is technologically feasible today for oil and gas operators to implement policies that would achieve widespread emissions reductions. The IEA estimates that existing technologies are capable of eliminating roughly three-quarters of global methane emissions arising from oil and gas operations.[23] A sweeping 2021 report on methane from the UN Environment Programme (UNEP) concluded that nearly half of all "readily available" emission reduction technologies apply to the fossil fuel sector, "in which it is relatively easy to reduce methane at the point of emission and along production/transmission lines."[24]

As a result of the economic and technical feasibility of widespread mitigation, oil and gas sector methane emissions are considered the low-hanging fruit of large-scale methane emissions reductions. Oil and gas operations are the place where the most progress can be achieved the fastest, a critical opportunity in an arena where success will be judged in years as well as decades.

Traditional Methods for Estimating Oil and Gas Sector Methane Emissions

Despite the favorable conditions for mitigation, oil and gas sector methane emissions remain an acute problem. Much of this paradox can be explained through the science of methane emissions from oil and gas operations: how they are calculated, how they are characterized, and how recent scientific advances have changed the way they can be understood and eliminated.

It has long been acknowledged that different parts of the oil and gas supply chain emit methane into the atmosphere under certain operational circumstances. The traditional procedure for estimating aggregate methane emissions from oil and gas infrastructure involves the use of "emission factors." These are engineering estimates of the amount of methane that would be expected to be released from a given component or type of equipment (such as valves, flanges, seals, and other connectors) under normal operating conditions. A study commissioned by EPA and the Gas Resources Institute in 1996 first recommended this approach for methane as part of a landmark, 15-volume report *Methane Emissions from the Natural Gas Industry:*

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[21] Ocko, Ilissa, et al. "Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming." *Environmental Research Letters*, vol. 6, no. 5, 4 May 2021, accessed here: https://iopscience.iop.org/article/10.1088/1748-9326/abf9c8.

[22] International Energy Agency. "Methane Tracker 2021." *IEA*, January 2021, accessed here: https://www.iea.org/reports/methane-tracker-2021.

[23] *Id*.

[24] United Nations Environment Programme and Climate and Clean Air Coalition. "Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions." *United Nations Environment Programme*, 2021, accessed here: https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions.

> "The techniques used to determine methane emissions were developed to be representative of annual emissions from the natural gas industry. However, it is impractical to measure every source continuously for a year. Therefore, emission rates for various sources were determined by developing annual emission factors for typical sources in each industry segment and extrapolating these data based on activity factors to develop a national estimate, where the national emission rate is the product of the emission factor and the activity factor."[25]

For oil and gas sector methane emissions, the emission factors approach was applied right away to support policy recommendations of massive consequence. The original 1996 report used emission factors to estimate the annual methane emissions of the U.S. natural gas industry for 1992 and found that 1.4% (+/- 0.5%) of gross natural gas production is lost to the atmosphere as methane emissions. Based upon this data, the report concluded:

> "…natural gas contributes less potential global warming than coal or oil, which supports the fuel switching strategy suggested by the IPCC and others."[26]

Regulatory agencies around the world, including the U.S. Environmental Protection Agency (EPA), still require oil and gas operators to use emission factors as the basis of their methane emission calculations. EPA's emission factor approach today is derived from rigorous engineering tests, is regularly updated to reflect more recent research, and allows operators to calculate emissions according to a consistent and stable methodology. EPA also factors in data from the limited direct measurements performed over oil and gas infrastructure using pre-approved observational tools in developing its estimates of methane emissions from the sector. When major abnormal leak events like the 2015 Aliso Canyon leak are identified and made known to EPA, the agency accommodates direct observations from those events in their inventories. But it must be understood that *emission factors are not actual real-world measurements of methane emissions*. Rather, they are based on static operating conditions that substitute narrow formulas for direct measurement, and are therefore vulnerable to mistaken assumptions and changing circumstances. A methane inventory based primarily on emission factors does not necessarily reflect actual emissions.

Scientific Advances and Inventory Underestimations

The heavy reliance on emission factors for taking inventory of methane leaks was a necessary concession at a time when the deployment of large-scale measurement capabilities within oil and gas basins was simply unrealistic. Indeed, until recently it would have been extraordinarily difficult on a technical and practical level to attempt any kind of broad alternative emission estimate. Recent technological advances, however, have made quantification a viable option.

[25] Environmental Protection Agency. "Methane Emissions from the Natural Gas Industry Volume 1: Executive Summary." June 1996, accessed here: https://www.epa.gov/sites/default/files/2016-08/documents/1_executive ummary.pdf.
[26] *Id*.

In recent years, scientists have been able to use newly sophisticated methane detection and quantification technologies to actually measure methane emissions from oil and gas operations. In particular, so-called "Top-Down" studies – which utilize platforms such as aircraft, satellites and tower networks to survey large areas, detect methane emissions, and quantify the size of those emissions – have provided researchers with the kind of broad, large scale measurement data that is necessary to infer aggregate emissions across large oil and gas basins. Academic researchers and non-profit organizations have embraced these methods and the insights they provide into the real-world characteristics of methane emissions from oil and gas operations.

The findings of this recent scientific research have been extraordinary. Measurement data across a range of studies has painted a consistent portrait of a much larger and more dangerous problem than previously understood. Since 2018:

- A landmark synthesis study in 2018 concluded that the EPA's Greenhouse Gas Inventory (EPA GHGI) – which is derived from emission factor estimates, and which EPA describes as providing "a comprehensive accounting of total greenhouse gas emissions for all man-made sources in the United States"[27] – underestimated methane emissions from the U.S. oil and gas supply chain by more than 60%.[28]
- An April 2020 study analyzed satellite data and determined that methane emissions from the Permian Basin exceeded the "bottom-up" estimate, based on EPA GHGI data, by "more than a Factor of 2."[29]
- A March 2021 study evaluated survey data from Japan's Greenhouse Gas Observing Satellite (GOSAT) and found that EPA's GHGI underestimates methane emissions from the oil and gas sectors by 90% and 50% respectively.[30]
- A May 2021 study assessed seasonal data on atmospheric ethane and deduced that the EPA GHGI underestimated oil and gas sector methane emissions by 48-76% nationally.[31]
- A March 2022 study reviewed aerial survey data and concluded that methane emissions from the New Mexico Permian Basin were a staggering 6.5 times larger than the corresponding EPA GHGI estimate.[32]

[27] Environmental Protection Agency. "Inventory of U.S. Greenhouse Gas Emissions and Sinks." 14 April 2022, accessed here: https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.
[28] Alvarez, Ramón, et al. "Assessment of methane emissions from the U.S. oil and gas supply chain." *Science,* vol. 361, Issue 6398, pp. 186-188, 21 June 2018, accessed here: https://doi.org/10.1126/science.aar7204.
[29] Zhang, Yu Zhong, et al. "Quantifying methane emissions from the largest oil-producing basin in the United States from space." *Science Advances*, vol. 6, issue 17, 22 April 2020, accessed here: https://doi.org/10.1126/sciadv.aaz5120.
[30] Maasakkers, Joannes, et al. "2010–2015 North American methane emissions, sectoral contributions, and trends: a high-resolution inversion of GOSAT observations of atmospheric methane." *Atmospheric Chemistry and Physics*, vol. 21, issue 6, pp. 4339-4356, 22 Mar. 2021, accessed here: https://doi.org/10.5194/acp-21-4339-2021.
[31] Barkley, Zachary, et al. "Analysis of Oil and Gas Ethane and Methane Emissions in the Southcentral and Eastern United States Using Four Seasons of Continuous Aircraft Ethane Measurements." *JGR Atmospheres,* 5 May 2021, accessed here: https://doi.org/10.1029/2020JD034194.
[32] Chen, Yuanlei, et al. "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey." *Environmental Science and Technology*, vol. 56, no. 7, pp. 4317-4323, 23 Mar. 2022, accessed here: https://doi.org/10.1021/acs.est.1c06458.

In simple terms, the U.S. oil and gas sector is emitting methane on a vastly larger scale than was previously known, and by a considerable amount more than the official inventory estimates maintained by the U.S. Government.

Methane Leaks

Recent scientific research has also coalesced around a consensus explanation for the systematic underestimation of oil and gas methane emissions. According to scientific measurement data, the largest sources of oil and gas methane emissions do not occur under the normal operating conditions that provide the basis for emission factors. Instead, the largest amount of methane is emitted when equipment does not work as designed and something goes wrong. It is these circumstances – which can broadly be characterized as *malfunctions and abnormal operating conditions* – that primarily facilitate methane emissions from the oil and gas sector. And it is these circumstances that are not properly captured by existing inventory estimates. As the 2018 synthesis study noted, "sampling methods underlying conventional inventories systematically underestimate total emissions because they miss high emissions caused by abnormal operating conditions (e.g., malfunctions)."[33] The phenomenon arising from such conditions is commonly known as *methane leaks*.

Crucially, not all methane leaks are alike. In recent years, researchers have utilized measurement data to establish that a small subset of massive methane leaks are responsible for a disproportionate amount of the oil and gas sector's total methane emissions. Though relatively few in number, these large-emission events – known as *super-emitting leaks* – are so enormous that they constitute one of the main drivers of contemporary oil and gas sector methane emissions:

- A study published in 2019 found that less than 0.2% of the methane-emitting infrastructure in California is responsible for over a third of the state's entire methane inventory.[34]
- A 2021 study used aerial survey data from the Permian Basin to conclude that 20% of emission sources were responsible for 60% of detected methane emissions during the survey.[35]
- Data released jointly by two scientific non-profit organizations in January 2022 revealed that super-emitting leaks may have contributed as much as 50% of total methane emissions from the Permian Basin between 2019 and 2021.[36]

[33] Alvarez, Ramón, et al. "Assessment of methane emissions from the U.S. oil and gas supply chain." *Science,* vol. 361, Issue 6398, pp. 186-188, 21 June 2018, accessed here: https://doi.org/10.1126/science.aar7204.
[34] Duren, Riley, et al. "California's Methane Super-emitters." *Nature,* Vol. 575, pp. 180-184, 6 Nov 2019, accessed here: https://doi.org/10.1038/s41586-019-1720-3.
[35] Cusworth, Daniel, et al. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science and Technology Letters*, vol. 8, no. 7, pp. 567-573, 2 June 2021, accessed here: https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173.
[36] Carbon Mapper, Environmental Defense Fund. "Dozens of "super-emitting" oil and gas facilities leaked methane pollution in Permian Basin for years on end." 24 Jan. 2022, accessed here: https://carbonmapper.org/dozens-of-super-emitting-oil-and-gas-facilities-leaked-methane-pollution-in-permian-basin-for-years-on-end/.

- A study published in February 2022 used satellite data to determine that a tiny number of "ultra-emitters" in the oil and gas sector were likely responsible for as much as 8-12% of global methane emissions from oil and gas operations.[37]
- A March 2022 study concluded from aerial survey data that a mere 12% of emission sources were responsible for 50% of detected methane emissions from the New Mexico Permian Basin during the survey.[38]

The predisposition of oil and gas operations to experience super-emitting leaks during malfunctions and abnormal operating conditions creates a so-called "tail-heavy" emission distribution, with a small number of extremely large leaks at the far end of the statistical distribution bearing the responsibility for much of the sector's aggregate methane emissions.

Beyond their sheer size, oil and gas sector methane leaks possess unique characteristics that must be understood. One of the most critical characteristics is *intermittency*. Researchers have found that many oil and gas processes tend to produce intermittent leaks, which essentially means that the leaks are prone to stopping and starting irregularly for extended periods of time. By contrast with persistent leaks, which emit methane steadily and continuously until they are repaired, intermittent leaks are extremely variable and unpredictable. In practice, they often manifest in almost random distribution patterns, making them far more liable to escape detection and very difficult to accurately profile. But they represent a substantial source of methane emissions. A 2021 study utilizing aerial survey data from the Permian Basin found that "highly intermittent sources" constituted 66% of all emission sources and 48% of all methane emissions.[39] Some of these intermittent sources may be attributable to routine process and maintenance emissions, but others are almost certainly methane leaks, and indeed are likely to include super-emitting leaks. The role of intermittent super-emitters is a well-established facet of oil and gas sector methane leaks, and aerial survey findings released earlier this year noted the frequent presence of large methane leaks that were "shorter in duration" at super-emitting facilities.[40] The precise contributions of intermittent super-emitters remain difficult to pinpoint, however, due to their unpredictability and the difficult challenge of using periodic surveys to detect and identify them throughout complex oil and gas supply chains.

The incidence of super-emitting and intermittent leaks has implications for the kinds of survey data needed to build a national profile of methane emissions. First, large numbers of measurements are required to develop accurate profiles of methane leak emissions from oil and gas operations. The fact that a small number of leaks contribute disproportionately to aggregate leak emissions increases the importance of conducting large sample size measurement surveys in

[37] Lauvaux, Thomas, et al. "Global assessment of oil and gas methane ultra-emitters." *Science*, vol. 375, issue 6580, pp. 557-561, accessed here: https://doi.org/10.1126/science.abj4351.
[38] Chen, Yuanlei, et al. "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey." *Environmental Science and Technology*, vol. 56, no. 7, pp. 4317-4323, 23 Mar. 2022, accessed here: https://doi.org/10.1021/acs.est.1c06458.
[39] Cusworth, Daniel, et al. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science and Technology Letters*, vol. 8, no. 7, pp. 567-573, 2 June 2021, accessed here: https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173.
[40] Carbon Mapper, Environmental Defense Fund. "Dozens of "super-emitting" oil and gas facilities leaked methane pollution in Permian Basin for years on end." 24 Jan. 2022, accessed here: https://carbonmapper.org/dozens-of-super-emitting-oil-and-gas-facilities-leaked-methane-pollution-in-permian-basin-for-years-on-end/.

order to detect and quantify as many super-emitters as possible. Second, and relatedly, larger measurement surveys will actually tend to increase emission estimates, because more super-emitters will be detected and the heavy-tailed emission distribution that characterizes methane leaks will be pulled further towards the extreme. This non-normal emission distribution is a vital feature of the problem. As one expert told the Committee staff, "methane leaks do not obey conventional statistics."

Implications of the Scientific Consensus for Methane Mitigation

Recent scientific research into the characteristics of methane leaks can inform the oil and gas sector's efforts to mitigate them:

- Due to the disproportionate role of super-emitting leaks in driving overall emissions from the sector, the focus of private sector LDAR programs should be super-emitting leaks. LDAR programs can best achieve swift, large-scale reductions in methane emissions if they are designed and equipped to detect and repair super-emitting leaks as quickly as possible, despite the relatively small number and frequently intermittent nature of such leaks. Tailoring LDAR programs to address super-emitters is a far more efficient way to cut methane emissions than prioritizing all methane leaks equally.

- Reorienting LDAR programs requires a better understanding of the characteristics of super-emitting leaks within oil and gas infrastructure. Quantification data is a prerequisite for identifying super-emitters, developing more accurate operator emission profiles based upon the existence of super-emitters, and anticipating the sources of super-emitters in order to survey them more frequently and make proactive operational changes to prevent them altogether. LDAR programs must be capable of quantifying methane leak emissions, both in the aggregate and at the level of individual super-emitting leaks.

- Methane leaks require a higher frequency of methane detection surveys than is mandated under current Federal regulations. Infrequent handheld LDAR surveys largely do not capture malfunctions and abnormal operating conditions, which give rise to persistent and intermittent super-emitting leaks. Innovative LDAR technologies, from aerial flyover and satellite sensors to drones and ground-based continuous monitoring sensors, hold tremendous promise for increasing the frequency of methane detection surveys and quantifying methane leaks. Innovative LDAR technologies are crucial to achieving large-scale emission reductions.

Finding #1: Oil and Gas Companies Are Failing to Address Super-Emitting Leaks

Overview

Existing oil and gas sector LDAR programs are failing to mitigate methane emissions from super-emitting leaks. The principal cause of this failure is the unwillingness of oil and gas companies to prioritize super-emitting leaks within their LDAR activities. In the view of the Committee staff, there are simple, concrete steps that companies can take today, using existing tools and methods, that would make significant progress towards reducing super-emitting leaks. But the companies remain tethered to a traditional "find and fix" approach that treats all methane leaks equally, despite the scientific evidence establishing that super-emitting leaks are one of the most significant drivers of sector-wide methane emissions.

Failure to Define Super-Emitting Leaks

The first step towards addressing super-emitting methane leaks is to define the size of a "super-emitter." The absence of an internal super-emission threshold indicates that oil and gas companies cannot formally distinguish the small subset of super-emitting leaks from the far larger mass of methane leaks within their operations. The lack of a definition also makes it far more challenging for operators to develop a more sophisticated understanding of their own super-emitting leaks. Assessing the characteristics, sources, and operational circumstances of super-emitters would help operators prioritize LDAR resources towards their prevention and rapid detection. Without a threshold definition of super-emitting leaks, however, such a thorough analysis – and the strategic direction that could be gained from it – is difficult to accomplish.

Based upon the Committee's findings, the oil and gas sector is failing to define the size of super-emitting methane leaks. Of the ten operators that provided information to the Committee, nine out of ten revealed that they lack any internal definition of a super-emitting leak, whether persistent or intermittent. Only one operator cited an actual size threshold for a super-emitting leak. Furthermore, many of the operators confirmed that they lack any useful internal classification of super-emitting leaks at all, either referencing broadly unrelated state reporting thresholds or simply acknowledging that they do not categorize super-emitting leaks in any manner.

At present, no formal consensus exists – either among regulators or within the scientific community – regarding a single, universal definition of a super-emitting methane leak. However, the lack of an industry-wide definition does not explain the failure of specific companies in the oil and gas sector to adopt internal definitions for their own purposes. Numerous scientific studies in recent years have made practical assumptions about the size of super-emitting leaks that can serve as models for oil and gas companies. For example, a 2017 study defined super-emitters as methane leaks with an emission threshold at or above 26 kilogram per hour (kg/hr) because such leaks "correspond to the highest-emitting 1% of sites in the site-based distribution, accounting for 44% of total site emissions" in the study's data set.[41] Many subsequent studies

[41] Zavala-Araiza, Daniel, et al. "Super-emitters in natural gas infrastructure are caused by abnormal process conditions." *Nature Communications*, vol. 8, no. 14012, 16 Jan. 2017, https://doi.org/10.1038/ncomms14012.

have adopted the same definition.[42] While the Committee staff does not endorse any particular definition for super-emitting leaks, we do note that the extensive scientific usage of 26 kg/hr as a threshold could provide a sensible approach for the private sector.

Case Study: A Flawed Definition of Super-Emitting Leaks

Only one operator indicated that it has established an internal size definition of a super-emitting leak. It is a positive step to affirm any threshold, and the Committee staff recognizes this operator's efforts. But the company's definition is flawed and does not offer significant value as a tool to assess methane super-emitters.

The operator defines super-emitting leaks in the Permian Basin as follows: "an unauthorized release of gas through venting and flaring into the environment as a result of an upset emission event or planned/unplanned maintenance activity over a reportable quantity (5,000 lbs. of natural gas)." It says that this definition is "in accordance with" a definition established by the Texas Commission on Environmental Quality (TCEQ). But the company did not offer a denominator of time (e.g. per hour, per day) to allow the metric to be expressed as a rate, which is critical to understanding the urgency of a leak from both a climate and localized safety perspective. If we assume the company is otherwise keeping with the TCEQ General Air Quality Rules, the period of time over which a "reportable quantity" is emitted in order to qualify as a "reportable emissions event" would be 24 hours:

> *Reportable emissions event--Any emissions event that in any 24-hour period, results in an unauthorized emission from any emissions point equal to or in excess of the reportable quantity as defined in this section.*

5000 lbs/24 hours is equivalent to 94.5 kg/hour, a figure nearly four times the 26 kg/hr threshold preferred by researchers. Additionally, the operator's metric refers to natural gas, rather than methane. While methane is the most prevalent constituent in natural gas, anywhere from 10-30% of natural gas is from non-methane components, such as ethane, butane, propane, carbon dioxide, volatile organic compounds (VOCs), and water vapor. To use the terms interchangeably for any kind of numeric threshold is imprecise. This operator's definition is an example of the perils of using ill-fitting traditional methods for the detection, analysis, and mitigation of super-emitting leaks.

Failure to Identify and Track Super-Emitting Leaks

Defining super-emitting methane leaks is a prerequisite to identifying and tracking them. Experts confirmed to the Committee staff that properly tracking super-emitting leaks is critical to mitigating methane pollution, and that gathering precise and specific data is the simplest way for companies to gain greater insights into the characteristics of super-emitting leaks within their operations. Choosing not to collect such data is effectively a choice to remain blind to the problem.

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[42] For example: Cusworth, Daniel, et al. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science and Technology Letters,* vol. 8, no. 7, pp. 567-573, 2 June 2021, accessed here: https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173.

The Committee staff have determined that oil and gas operators are making that choice. All ten operators conceded that they do not identify, track, or maintain records in any organized manner regarding super-emitting methane leaks within their Permian operations. These statements are even more striking in light of the fact that innovative LDAR technologies, which can identify and provide the data necessary to track super-emitters, are available for deployment today. Many of these innovative technologies quantify the size of methane leaks and can therefore identify super-emitters for operators quickly, making their documentation simply a matter of recording and organizing the data. The opportunity for operators to classify super-emitting leaks is clear. Operators simply must be willing to seize it.

Case Study: An Operator's Dismissal of Tracking Super-Emitters

One of the operators wrote to Chairwoman Johnson:

> *Our aim is to identify and mitigate emission leaks. As such, the company does not maintain documentation around large-emission methane leaks separately from other leaks identified by monitoring conducted at our sites. … Since leak detection and repair are our objectives, [the company] does not maintain a list of all intermittent, large-emission methane leaks identified by our monitoring technologies…*

This operator appears to believe that the identification and tracking of super-emitting methane leaks should be viewed distinctly from the larger need to "identify and mitigate emission leaks." The company's approach neglects the vital role that super-emitter data must play in supporting science-based LDAR approaches, and it does not reflect the current scientific evidence regarding the causes of oil and gas sector methane emissions.

Failure to Assess the Contribution of Super-Emitting Leaks to Overall Methane Emissions

One of the primary reasons to identify and track super-emitting methane leaks is to understand the contributions that super-emitters make towards a particular operator's aggregate methane emissions. Scientists have conducted extensive research into the immense role played by super-emitters as a driver of oil and gas sector methane emissions, but these studies tend to gather data on a large geographic scale, encompassing a multitude of operators within a particular oil and gas field, basin, or region. For individual companies, understanding the share of methane emissions that results from super-emitting leaks specific to their own facilities and equipment would help them assess the performance of their assets, evaluate the success of LDAR programs and technologies, improve the quality of assertions about the sustainability and climate intensity of their products, and develop emissions mitigation strategies. To act comprehensively against super-emitting leaks in an informed manner, each company needs to grasp the problem unique to its own operations.

The Committee's findings indicate that the oil and gas sector cannot do so. All ten operators asserted that they do not presently assess the contribution that super-emitters make towards their aggregate methane emission in the Permian Basin. When it comes to the role of their own super-emitters in the Permian, all ten operators are in the dark.

For specific companies to evaluate the role of super-emitting leaks in driving total methane emissions within their operations, they must be prepared to perform statistical analyses of emission quantification data regarding both super-emitters and aggregate methane emissions. The process for doing so is technically challenging, but it is achievable using existing technology, as scientific researchers have amply demonstrated. At a minimum, even rudimentary efforts to assess methane emissions derived from super-emitters (along with their rate of occurrence) would still provide companies with valuable insights into the impact that such leaks would be likely to have on their overall emissions profile. Simply grasping the overall scale of super-emitting methane leaks, even imprecisely, would likely enhance the understanding that companies possess concerning the emissions profile of their operations.

Failure to Prioritize Super-Emitting Leaks within LDAR Design and Implementation

Beyond gathering and analyzing data, there are concrete actions that oil and gas operators can take – rooted in the latest science and utilizing existing technologies – which would strengthen their LDAR efforts against super-emitting leaks. Distinguishing the relative size of methane leaks cannot be done using the traditional tools of regulatory LDAR programs such as handheld optical gas imaging (OGI) cameras, which lack the capability to quantify emissions. Innovative LDAR technologies must be deployed over oil and gas operations as a foundation of a super-emitter mitigation strategy. But the deployment of these technologies, while necessary, is not sufficient. Just as important is the framework in which companies deploy them, and the processes that are put in place by companies to effectively utilize them.

- The first essential aspect of an LDAR framework for super-emitting methane leaks is to achieve as high a frequency of detection surveys as possible, with a scope that encompasses an operator’s entire infrastructure. More comprehensive and more frequent surveys are among the simplest and most effective steps that oil and gas operators can take to reduce the impact of super-emitting leaks. The goal is simply to ensure that monitoring systems are in place to detect super-emitting leaks as fast as possible wherever they might appear. Given the high cost and labor-intensive nature of handheld OGI surveys, the only practical way to achieve the necessary scope and frequency is to deploy innovative LDAR technologies using platforms that are capable of monitoring large distances at a higher tempo, such as fixed-wing aircraft, ground-based sensor networks, helicopters, drones, and/or satellites.

- It is also critical that companies properly utilize the data generated by innovative LDAR technologies to prioritize super-emitting leaks in repair efforts. Many innovative technologies can provide operators with data regarding the size of individual methane emission events within their operations. But the operators themselves must accept the validity of these measurements, integrate the measurement data into their repair procedures, and respond to super-emitting leaks as quickly as possible. Operators must implement an analytical framework that emphasizes larger leaks as the primary focus of

LDAR programs. In the absence of that framework, all leaks will be treated equivalently and a vital opportunity to cut one of the largest sources of methane emissions will be lost.

- Finally, it is essential that oil and gas companies employ the measurement data at their disposal to prioritize the root causes of super-emitters, in terms of both LDAR responses and operational changes. Operators can employ that quantification data in support of numerous actionable steps, such as identifying facilities and types of equipment that are more likely to experience super-emitting events; redirecting limited LDAR resources in a more efficient and targeted manner towards aspects of the company's infrastructure with a higher prevalence of super-emitters; and devising operational changes that target areas of high super-emitter vulnerability, such as replacing particular pieces of equipment with less susceptible alternatives. These types of actions hold tremendous promise for the mitigation of methane leak emissions. But to implement them, operators must accept the need for data regarding super-emitting leaks and act on that data.

In terms of the frequency and scope of LDAR surveys, the Committee staff is encouraged to observe so much interest among operators in voluntarily exploring the use of innovative technologies to bolster their LDAR efforts. However, as will be discussed later in this report, it must be noted that most of these activities remain in the realm of pilot testing programs, rather than the comprehensive, scaled-up operational programs that are necessary to achieve major methane reductions. There is still a long way to go before widespread deployment can truly achieve large-scale emissions reductions.

Even where oil and gas companies are deploying innovative LDAR technologies at greater frequency and scope, flawed approaches are undermining the ability of LDAR programs to target super-emitting leaks. In response to Chairwoman Johnson's request for information regarding any "specific LDAR procedures or initiatives" in their LDAR programs designed to address methane super-emitters, and intermittent super-emitters specifically, the ten operators provided lean answers and scant evidence of deliberate effort to mitigate super-emitters. Several argued that the same longtime practices associated with traditional LDAR programs, such as Audio, Visual and Olfactory (AVO) inspections, can be refocused to address super-emitting methane leaks as well. Some cited the use of remote operational monitoring systems that can detect equipment disruptions which may indicate leaks, without acknowledging that such systems cannot themselves distinguish between the small number of super-emitters and the far larger mass of tiny leaks. A few operators argued that distinct procedures to address super-emitting leaks were simply unnecessary, as traditional practices were sufficient to solve the problem, or declined to specify any targeted procedures at all. These responses indicate a troubling lack of initiative on the part of the oil and gas sector to proactively implement LDAR practices designed to reduce super-emitting leaks.

Case Study: An Operator's Rejection of Focused Procedures for Intermittent Super-Emitters

In response to Chairwoman Johnson's question regarding LDAR practices for intermittent super-emitters, one operator argued that "boots-on-the-ground" inspections represented the most effective method for mitigation:

> *Though [the company] does not characterize leaks by their intermittency or scale, the company performs LDAR surveys to identify and thereby reduce the impact of any leaks found, regardless of size or duration. [The company] believes lease operator training and in-person inspections (a/k/a "boots-on-the-ground" inspections) are the best way to deter releases. … Training and in-person inspections will allow [the company] to respond to an intermittent, large-emission methane leak if one should occur in the future.*

But these types of inspections are inadequate for reducing super-emitting leaks at scale. In the view of the Committee staff, "boots-on-the-ground" LDAR methods cannot on their own be scaled up to solve the problem of super-emitting methane leaks, whether intermittent or persistent.

There is one significant exception to this lack of progress. The Committee staff does acknowledge that some oil and gas companies are taking an encouraging first step by using the measurement data from innovative LDAR technologies to prioritize the largest methane leaks for repair. The use of measurement data in this manner represents a tangible shift in a positive direction.

But other operators do not appear to use the measurement data at their disposal in this way. Instead, they take the traditional "find and fix" approach, regardless of any data that suggests the relative size of a leak. This "find and fix" approach treats all methane leaks equivalently, regardless of the size of their emissions. While the goal of repairing every methane leak is surely commendable in the abstract, an LDAR framework that fails to distinguish between the large mass of tiny methane leaks that occur constantly and the small group of super-emitting methane leaks that are responsible for a disproportionate amount of oil and gas methane emissions is deeply flawed. Any oil and gas company that fails to utilize measurement data it already has to prioritize super-emitting leaks is wasting an opportunity to reduce its methane emissions.

Other than the basic step taken by some operators to direct repair surveys towards larger leaks, the oil and gas sector appears to be doing very little to devise LDAR procedures and practices for the purpose of mitigating super-emitting methane leaks. A large part of this failure is rooted in a reluctance on the part of the operators to redesign their existing LDAR procedures around super-emitter data and intermittency data derived from innovative LDAR technologies. This data offers tremendous potential to improve the ability of LDAR programs to detect more super-emitting leaks and organize LDAR responses more effectively to ensure successful repair. But to maximize its impact, operators must be willing to apply it in the context of super-emitters. For example, some innovative LDAR technologies distinguish between persistent and intermittent leaks. But if operator LDAR programs fail to record, track and follow-up on intermittent leaks, many of these leaks – including the super-emitters among them – are likely to fall through the cracks if they cannot immediately be repaired.

Case Studies: The Importance of Integrating Data on Intermittent Super-Emitters into LDAR Procedures

In its response to Chairwoman Johnson, one operator noted that it currently does evaluate measurement data from an aerial survey vendor to prioritize larger leaks for mitigation. However, this operator also acknowledged that while the vendor provides data regarding leak intermittency, the operator has not developed distinct LDAR procedures for responding to intermittent leaks as opposed to persistent leaks. Moreover, the operator stated that it does not distinguish intermittent leaks in its LDAR system, despite the risk that intermittent leaks may be far more difficult to detect and repair during follow-up surveys after the initial detection due to the erratic and unpredictable nature of their emission releases.

The Committee staff believe that this could significantly undermine the ability of this operator's LDAR program to reduce methane emissions from intermittent super-emitters. If the company does not distinguish large intermittent leaks internally, it cannot track which of those leaks managed to avoid detection during initial follow-up surveys and therefore require additional follow-up. As a result, intermittent super-emitters could be allowed to resume emitting methane until another detection survey happened to detect the leak again.

Internal methane leak data obtained by the Committee from a different operator highlights the risks of failing to account for intermittent leaks. According to aerial survey data generated on that company's behalf in 2021, a significant percentage of emission events recorded in two aerial surveys – 28% and 37%, respectively – were investigated by the operator after detection, but could not be found in follow-up surveys with handheld optical gas imaging (OGI) devices. This second operator disclosed that it only pursues OGI follow-up for persistent emissions and large intermittent emissions. Thus, it is likely that these "unidentified" emissions were large, intermittent leaks.

The fact that intermittent super-emitters likely constitute a substantial percentage of the second operator's leak profile demonstrates the limitations of the first operator's approach. Large intermittent leaks are frequent but may not re-appear in a single follow-up survey. LDAR programs must develop procedures to anticipate and address them specifically.

Similarly, the oil and gas sector appears to be making little effort to use measurement data to inform operational changes and the more efficient deployment of traditional LDAR resources towards the root causes of super-emitting leaks. In their responses, a number of operators did detail longstanding efforts to improve the operational efficiency of their facilities and equipment, in some cases with assistance from innovative LDAR technologies. These initiatives are worthy endeavors. The missing element, however, is the focus on super-emitting methane leaks specifically as the aim of targeted operational changes to mitigate leak emissions. The problem, once again, is that determining the operational changes capable of reducing the prevalence and duration of super-emitting leaks requires concrete, reliable data on super-emitters within an operator's infrastructure. Without such data, it is extremely difficult to understand what types of operational changes directly concentrate their impact on super-emitters, and where LDAR resources can be shifted to survey operational aspects more vulnerable to super-emitters at a greater frequency. Data and practice must go hand-in-hand to develop more effective LDAR efforts for mitigating super-emitting methane leaks.

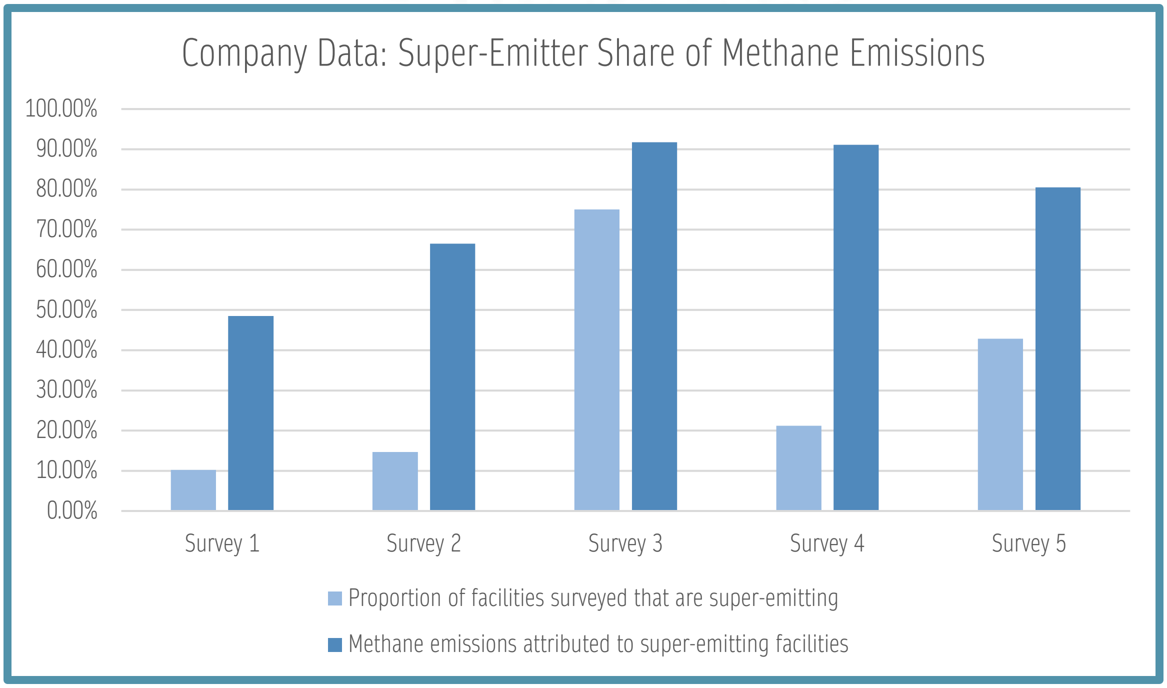
Super-Emitting Methane Leaks: Internal Company Data

Committee staff obtained the results of nine methane detection surveys conducted for several operators in the Permian Basin. These surveys, which were commissioned by the operators, used innovative LDAR technologies to detect methane leaks and quantify the size of their emissions. The data confirms unequivocally what recent scientific research has indicated: super-emitting leaks are an immense driver of oil and gas methane emissions, and they are emitting methane at extraordinary levels.[43]

Five surveys were selected for closer analysis due to their relatively broad scope. The combined emission rates of facility-level super-emitting leaks in the five surveys ranged from 189.4 kg/hr to 1,353.8 kg/hr. The survey that detected the fewest number of super-emitters was also the survey that was most narrow and limited in scope, supporting the scientific view that large numbers of measurements are critical to properly characterize the emission distribution of oil and gas operations. Meanwhile, a larger survey of a different company's assets, an aerial survey conducted in 2021, detected 18 distinct super-emitters within the company's operations over just three days of flyovers, ranging in size from roughly 26 kg/hr to over 400 kg/hr.

The company data also reveals the disproportionate share of methane emissions contributed by super-emitting leaks as a share of an operator's aggregate leak emissions. Among the five surveys, facility-level super-emitters were responsible for between 49% and 91% of all detected emissions in each survey, despite constituting a small number of overall leaks. In an aerial survey of one operator's facilities, just 4 super-emitting facilities were responsible for 49% of all detected methane emissions. In a different aerial survey, just 5 super-emitting facilities were responsible for 67% of all detected methane emissions. In a drone survey of an operator's facilities, just 7 super-emitting facilities were responsible for 91% of all detected methane emissions.

[43] For purposes of this analysis, the Committee staff has defined a super-emitting leak as any emission event equal to or greater than 26 KG/HR. When emission rate data was originally calculated in Standard Cubic Feet Per Hour (SCFH), the Committee converted SCFH to KG/HR using a simple calculation whereby the rate of emitted gas in SCFH was multiplied by 0.0192 kg/scf and then multiplied again by 0.8 to represent a standardized fractional methane content of 80% methane.



The single largest leak in any survey reviewed by the Committee emitted 413.9 kg/hr. This one leak was so large that its emission rate turned out to be roughly 26% larger than the combined emission rates for *all* non-super-emitting leaks detected in the survey. The leak is an illustration of why it is so critical to focus methane reduction strategies on mitigating super-emitters: in this instance, the operator could achieve greater emissions reductions by detecting and repairing a single leak than by repairing the two dozen small leaks that were also detected.

The Committee also observed that the largest leak identified during one of the surveys was an intermittent super-emitter. It was recorded emitting at 66 kg/hr one evening in 2021, but the leak had ceased on its own the following day. Without continuous monitoring, it is difficult to know whether this facility experiences large but sporadic emissions events.

A 2020 drone survey demonstrated how LDAR quantification data can inform future leak mitigation strategies. That survey identified a pattern: out of seven facility-level super-emitters, five of them – including the three largest leaks, all larger than 100 kg/hr – were caused by compressors. Researchers have identified other equipment types as leading sources for super-emitting leaks as well, including flares and tanks, and we do not suggest that compressors are particularly leak-intensive based upon this one data set. Such a data point can serve as a foundation for further research and analysis by this specific operator in order to develop a more accurate understanding of its own leak emission profile, and to isolate potential problems that may lend themselves to operational changes to avoid leaks.

After reviewing this data, the Committee staff do not have any doubt that many oil and gas companies are aware of the threat posed by super-emitting methane leaks within their own operations. Their own internal data confirms it. Operators that conduct methane detection surveys using innovative LDAR technologies are likely to confirm that a small number of very large methane leaks are responsible for a disproportionate share of overall methane emissions.

They know how grave the super-emitter problem is. And yet, they are still failing to take the simple steps necessary to make it a mitigation priority. The oil and gas sector cannot avoid responsibility for confronting super-emitting methane leaks by claiming that the science is uncertain, as their own data says otherwise.

Finding #2: Oil and Gas Companies Are Failing to Use Quantification Data to Mitigate Methane Leak Emissions

Overview

The Committee has determined that the capability to quantify methane emissions exists, but the oil and gas sector is not operationalizing it.

In the view of the Committee staff, quantification represents an immensely valuable tool to understand the scale of the methane leak problem and inform solutions to address it. While existing quantification tools may possess some technical limitations that will require further research and development to address, they can nevertheless be used by oil and gas companies – right now – to obtain extremely useful information about the size of methane leaks and the total methane emissions from their operations in a given basin, as well as the sources of those emissions and their operational emission profile. By rejecting the use of quantification data for reasons that are not scientifically justified, the oil and gas sector has chosen to remain in the dark about the alarming reality of its methane leak problem and the need to reduce methane leak emissions at a far more rapid pace. Unless the sector embraces methane leak quantification immediately, it will not be able to achieve the rapid and large-scale decline in methane emissions that is necessary for America to reach its methane reduction goals.

Survey of Innovative LDAR Quantification Capabilities for Oil and Gas Operators

In response to Chairwoman Johnson's request for information regarding their deployment of innovative LDAR technologies, the ten oil and gas operators provided detailed descriptions of the technologies currently being piloted or scaled-up within their Permian operations. Many of these technologies can quantify the size of methane emission events, including those events caused by malfunctions and abnormal operating conditions.

Oil and Gas Operator Current Permian Deployments of Innovative LDAR Technologies with Quantification Capabilities

Operator	Technology Deployed w/ Quantification Capability?	Type of Sensor Platform	Status	Does Operator Use Data to Quantify Methane Emissions?
Admiral Permian Resources	Yes	Ground-Based Continuous Monitoring	Pilot Program	No
Ameredev	Yes	Ground-Based Continuous Monitoring	Pilot Programs	No
Chevron	Yes	Aerial Survey	Basin-Wide Deployment	No
ConocoPhillips	Yes	Ground-Based Continuous Monitoring	Pilot Programs	No
Coterra Energy	Yes	Aerial Survey;	Basin-Wide Deployment; Pilot Programs	No

		Ground-Based Continuous Monitoring		
Devon Energy	Yes	Aerial Survey; Ground-Based Continuous Monitoring	Basin-Wide Deployment; Pilot Program	No
ExxonMobil	Yes	Aerial Survey	Basin-Wide Deployment	No
Mewbourne Oil	Yes	Aerial Survey; Ground-Based Continuous Monitoring	Pilot Program; Basin-Wide Deployment	No
Occidental Petroleum	Yes	Aerial Survey; Ground-Based Continuous Monitoring; Satellite	Basin-Wide Deployment; Pilot Programs; Pilot Program	No
Pioneer Natural Resources	Yes	Aerial Survey	Basin-Wide Deployment	No

All the oil and gas companies the Committee surveyed have been piloting innovative LDAR technologies that can quantify methane leak emissions in the Permian. Some are launching basin-wide deployments. Indeed, several experts observed to Committee staff that widespread pilot efforts are underway nationwide, and that 2021 witnessed a notable shift from pilot deployments to large-scale deployments among certain operators. But not one of the ten operators acknowledged using quantification data for the purpose of estimating basin-wide methane emissions, calculating emissions reductions, or developing a more accurate emissions profile for their Permian operations based upon the quantification of emission sources.

Importance of Quantifying Methane Leak Emissions

Recent scientific research has left little doubt that we are in the dark regarding the true size of oil and gas sector methane emissions. Indeed, emission factors fail to account for the essential characteristics of oil and gas methane leaks to such a degree that one expert called them “actively misleading” in terms of the scale of oil and gas methane emissions. But supplementing emission factor engineering calculations with frequent, high-resolution, real-world measurements – quantification data – is the key to understanding the problem and learning the observable ground truth.

The benefits of quantifying methane leak emissions though direct observations are enormous. Quantification data allows for much more accurate calculations of overall leak emissions from oil and gas operations. Since the fundamental shape of oil and gas methane emissions is characterized by a heavy-tailed emission distribution that is dominated by a relatively small number of super-emitting leaks, the only way to fully understand it is to conduct widespread and frequent emissions measurements throughout oil and gas infrastructure. Detecting and quantifying as many super-emitters as possible in order to properly characterize the magnitude of the tail is the key to understanding total emissions with greater accuracy. As a result, the quantification data derived from large measurement surveys – whether basin-wide aerial surveys, multi-facility fixed-sensor continuous monitoring systems, or any other innovative LDAR platform – provides the most accurate estimate that can currently be generated for actual methane emissions from oil and gas operations.

Case Study: A Missed Opportunity to Use Quantification Data in LDAR Analysis

The Committee reviewed information from one operator pertaining to an analysis of aerial survey data generated on the operator's behalf over two surveys in 2021. This operator analyzed the individual emission events detected during each survey and examined all confirmed methane leaks by segment: production, gathering and boosting, and pipeline or gathering line. However, the operator did not break down the leaks themselves and did not incorporate quantification data into its evaluation. The operator confirmed to the Committee staff that quantification is not included in its aerial survey analysis, even though the aerial survey vendor provides it.

This is a missed opportunity for the operator to use quantification data to deepen its understanding of methane leak emissions within its operations. For example, it would be extremely valuable to assess the number and size of super-emitting leaks by segment, which could yield important insights into their causes, the need for certain operational changes, and the prioritization of LDAR resources. It would be similarly beneficial to assess the number and size of intermittent super-emitters by segment. This is the type of analysis that is required to reorient LDAR programs towards mitigating the biggest sources of methane emissions in an informed, data-driven manner.

Quantifying methane emissions can support an array of beneficial outcomes. Measurement data allows for more precise and informed analyses of methane emission sources from oil and gas operations, targeted to specific segments, specific facilities, and even specific types of equipment. It can inform operational changes to eliminate circumstances that are more likely to produce super-emitting leaks. It can enable the reorientation of LDAR resources to emphasize more frequent inspections covering infrastructure with a greater propensity to experience super-emitters. It can provide the necessary data for operators to conduct cost-benefit calculations for innovative LDAR technologies on the basis of the savings that can be realized if captured gas were brought to market instead of leaking, which can be critical to help operators assess the financial incentives of adopting novel LDAR solutions.

In addition, quantification is needed for measurable, performance-based mechanisms by which oil and gas companies can respond to market demands for reduced methane emissions from their operations. The business case for methane quantification is growing stronger with each passing year. Shareholders deemed "socially responsible investors" are evaluating companies on Environmental, Social, and Corporate Governance (ESG) metrics.[44] Financial institutions and third-party ratings providers evaluate companies using available data on carbon emissions, pollution, use of renewable energy, and more, allowing shareholders and potential investors to compare companies' performance to their peers and make investment decisions in line with their

[44] Corporate Finance Institute. "ESG (Environmental, Social and Governance)." 6 May 2022, accessed here: https://corporatefinanceinstitute.com/resources/knowledge/other/esg-environmental-social-governance/.

values.[45] The market valuation of ESG funds is massive and growing rapidly, with an estimated $330 billion in assets under management estimated at the end of 2021.[46]

Similarly, a Responsibly Sourced Gas (RSG) designation allows oil and gas companies to boost their ESG metrics by obtaining a certification from a third-party program attesting to the company's environmental performance. No industry-wide standard for RSG currently exists, but more and more oil and gas companies are seeking RSG designation and affixing a 1-2% premium on RSG gas over non-certified products.[47] The move towards such certifications demonstrates that consumers and shareholders are interested in being more informed about the climate impact of the energy products they are using and investing in.[48] In addition, the European Commission is moving toward formal preference for RSG. It proposed legislation in the European Union in late 2021 that would require new, detailed information from gas suppliers on emissions measurement, reporting, verification, and mitigation strategies. It has also laid plans for more stringent methane regulations for Europe by 2025.

Methane emissions quantification seems indispensable for objectively assessing whether oil and gas companies are meeting ESG and RSG standards throughout the oil and gas supply chain. As a result, quantifying methane emissions will be an important economic consideration for oil and gas companies, and a capability that would be in their self-interest to utilize if they have a good story to tell investors and shareholders. The appeal of using quantification in this arena is already becoming apparent. For example, in May 2022, Chevron shareholders approved a shareholder resolution directing the company to assess the reliability of its methane measurement data. The resolution, supported by the owners of 98% of the company's stock, directed the company to inform its investors if company measurement data for methane emissions differed from publicly reported data.[49] It will be difficult for Chevron to fully align with the position of its shareholders without embracing LDAR quantification tools.

Innovative LDAR Quantification Capabilities

The benefits of quantifying oil and gas sector methane leak emissions are clear, but the capabilities are contested. Traditional LDAR technologies such as OGI cameras, which are approved for Federal regulatory purposes, cannot quantify methane emissions. Can innovative LDAR technologies do it? This is the heart of the matter. After consulting with a broad range of researchers and stakeholders across the oil and gas spectrum, the Committee staff has concluded

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[45] Huber, Betty and Comstock, Michael. "ESG Reports and Ratings: What They Are, Why They Matter." *Harvard Law School Forum on Corporate Governance*, 27 July 2017, accessed here: https://corpgov.law.harvard.edu/2017/07/27/esg-reports-and-ratings-what-they-are-why-they-matter/.
[46] Norman, Greg, et al. "ESG: 2021 Trends and Expectations for 2022." *Harvard Law School Forum on Corporate Governance*, 25 Feb. 2022, accessed here: https://corpgov.law.harvard.edu/2022/02/25/esg-2021-trends-and-expectations-for-2022/.
[47] Freitas Jr., Gerson. "'Responsibly Sourced' Gas Finds a Niche, But Some Cry Greenwashing." *Bloomberg*, 19 Jan. 2022, accessed here: https://www.bloomberg.com/news/articles/2022-01-19/natural-gas-trying-to-rebrand-as-greener-pitches-responsibly-sourced-fuel.
[48] ETF Trends. "These Institutional Investors Are Showing ESG Enthusiasm." *NASDAQ*, 20 Jan. 2022, accessed here: https://www.nasdaq.com/articles/these-institutional-investors-are-showing-esg-enthusiasm.
[49] Anchondo, Carlos. "Exxon, Chevron shareholders approve climate proposals." *E&E News*, 26 May 2022, accessed here: https://subscriber.politicopro.com/article/eenews/2022/05/26/exxon-chevron-shareholders-approve-climate-proposals-00035227.

that existing quantification capabilities possess real limitations but nevertheless *are capable of quantifying methane emissions from oil and gas operations and supporting methane mitigation activities*.

Quantification data serves two goals: measuring the size of individual methane leaks and calculating aggregate methane emissions from the entire set of measurements. To measure the size of individual emission events, innovative LDAR technologies deploy sensors to detect methane concentrations and then use data analytics, based upon set parameters, equations, and models, to convert the underlying concentration data into a quantified methane emission rate for each event. While the sensitivity of the sensors plays an important role in determining the threshold above which methane emissions can be reliably detected by a given technology, the data analytics are the key element in interpreting the size of an individual methane leak. Depending on the type of deployment platform utilized by an LDAR system, a large number of measurements may be taken over a given area during a given period. For example, thousands of individual measurements can be taken during an aerial survey conducted using fixed-wing aircraft, while certain ground-based fixed sensor networks can monitor continuously over a period of months or longer.

These large sets of individual measurements can then be aggregated to inform a total methane emission rate over a covered area and attribute relative emission rates to different sources within that area. In this instance, a "covered area" can refer to any subset of oil and gas infrastructure that is encompassed within a methane detection survey or system, from a single facility to a set of facilities to an operator's entire basin-wide infrastructure. The basis for these aggregate emission calculations is the multitude of individual emission measurements taken by an innovative LDAR system. The calculations require considerable statistical expertise to perform, particularly for large areas. These types of analyses have served as the foundation of much of the recent scientific research that has revolutionized our understanding of the scale of oil and gas sector methane emissions. They have also provided invaluable insights into the sources of oil and gas sector methane emissions by segment and asset type.

The distinction between the quantification of individual methane leaks and the quantification of aggregate methane emissions represents the crux of the disagreement over the value of quantification data.

Existing innovative LDAR technologies possess genuine limitations that significantly reduce the accuracy and/or precision of the quantification data regarding individual emission measurements. A number of experts informed us that the uncertainty bands for individual methane measurements can be very large; common uncertainty bands can be at least +/- 20-30% per measurement, and in some instances as wide as +100% and -50%. According to a range of stakeholders, the primary causes of the significant uncertainty for individual quantification measurements arise from the difficulties encountered by LDAR technologies when integrating complex environmental factors into their quantification models and data analytics. In particular, the challenge of accurately modeling wind conditions was widely cited as one of the foremost shortcomings with contemporary quantification capabilities. Additional limitations can revolve around modeling the distance of a sensor from an emission source or the stability of a sensor's measurements, depending on the deployment platform being used. All of these factors represent aspects of methane quantification that would benefit from additional research investments.

But these limitations, as real as they are in terms of quantifying individual emission events, tell only part of the story of quantification's value. In terms of individual emission measurements, it is important to remember that super-emitting methane leaks are so large that they can still be quantified accurately enough to inspire confidence regarding the relative enormity of a leak, even if the exact size remains uncertain. This is a critical caveat to the legitimate concerns about quantification uncertainty. While such measurements remain subject to wide uncertainty bands, the sheer magnitude of super-emitters means that existing quantification technologies can reliably quantify their general size and provide invaluable support for more efficient operator LDAR programs, targeted operational changes, and a more accurate understanding of methane leak profiles.

In addition, experts told the Committee staff that while some innovative LDAR technologies are more mature than others, each type of system can be valuable for quantification purposes if deployed and interpreted effectively. For example, the quantification capabilities of aerial survey technologies are quite advanced regarding detected super-emitters, but their periodic surveys represent only a snapshot in time based upon a limited number of measurements. By contrast, the quantification capabilities of ground-based continuous monitoring technologies are generally subject to larger uncertainty bands, but their ability to broadly quantify super-emitters is nevertheless extremely valuable due to the sheer number of measurements that they are able to take on a continuous basis, which allows for the detection and quantification of more large leaks at a more rapid pace than periodic surveys. If understood properly, quantification data can be *useful* even if it is also *uncertain*.

Furthermore, a range of experts told Committee staff that despite the uncertainties associated with individual measurements, innovative LDAR technologies that exist today are indeed capable of accurately quantifying total methane emissions from a particular area. The reason is simple: emission quantification estimates based upon a large number of measurements are subject to far less uncertainty than the uncertainty associated with each individual emission measurement might suggest. Over the course of many measurements, the average of the individual measurements gravitates towards the mean of the entire set of measurements, and the uncertainty of the overall data declines substantially. Thus, larger sample sizes and repeat measurements reduce uncertainty within aggregate emission estimates substantially, even to the point where more frequent, less accurate measurements may produce better aggregate emission estimates than less frequent, more accurate measurements. A significant amount of research, including from the oil and gas sector itself, endorses this point. For example, a presentation made by ExxonMobil at the American Geophysical Union's annual meeting in 2020 – based upon the company's own internal research using quantification data from innovative LDAR technologies, and provided to the Committee – concluded that even when individual measurements are unreliable, a large group of measurements can produce statistically significant results regarding site-level methane emissions.

Oil and Gas Sector Failure to Apply Methane Quantification

Contrary to the science, the oil and gas sector appears extremely reluctant to accept the value of quantification data for the mitigation of methane leaks. Many oil and gas companies currently possess information that clearly and unequivocally quantifies their operational methane emissions with real-world measurements. But while all ten operators are deploying technologies that collect quantification data, not one of them reported using quantification data to support operational decision-making, to improve their basin-wide methane emissions estimates, or to calculate emissions reductions that may result from changes they have implemented.

Why isn't the oil and gas sector using methane emissions quantification data to strengthen its LDAR initiatives and accelerate emissions reductions from its operations? In their responses to the Committee, the ten operators argued that they were unwilling or unable to use – for almost any purpose related to methane leaks – the quantification data at their disposal. Their positions, while distinct from operator to operator, broadly rested upon three arguments:

- Individual emission measurements are subject to considerable uncertainty
- Quantification data lacks the accuracy required to act on it
- The use of quantification data is unnecessary to achieve the objectives of methane leak detection and repair

Uncertainty

Several operators cited the large uncertainty bands associated with emission measurements from innovative LDAR technologies in explaining their resistance to the use of quantification data. While they acknowledged that the detection sensors themselves were quite reliable at detecting emission events above a certain threshold, they noted that individual measurements possessed a great deal of uncertainty, leaving them reluctant to utilize quantification data as a part of their LDAR activities or to analyze quantification data in order to inform operational changes. The sole exception, as noted previously, was the willingness of several operators to use quantification data to prioritize immediate LDAR responses to larger emission detections. But those operators rejected the idea that the technology was capable of quantifying the actual size of each emission event with enough certainty to apply the data to other contexts and uses.

Case Studies: Oil and Gas Operator Perspectives on Quantification Uncertainty

Operator #1:

> *The ability to estimate and quantify methane emissions utilizing innovative LDAR technologies continues to evolve. To date, [the company's] focus has been on the evaluation of innovative LDAR technologies to find and fix leaks on a broader scale in order to improve the company's emissions performance. ... There are ongoing efforts to advance quantification capability, but it should be noted that these estimates are based on algorithms and dispersion modeling and are subject to varying levels of uncertainty.*

Operator #2:

> *While we have identified encouraging progress in methane detection technology, there are currently limitations in obtaining direct measurements of emissions. Today, direct measurement faces uncertainties and challenges related to modeling wind conditions and plumes, complexities of data management infrastructure, accounting for changing conditions at a site over different time periods, scalability, and ability to provide timely data.*

Operator #3:

> *...emission rates predicted by modeling are not necessarily a good representation of actual emission rate. Therefore, [the company] primarily uses the methane concentration and duration of the change in concentration to identify leaks. It does not rely on any quantification of actual emissions.*

Some of the concerns expressed by the operators about measurement uncertainty are legitimate. Methane monitoring and detection would greatly benefit from further technological and analytical advances to reduce the uncertainty bands associated with quantifying individual methane leaks. But these concerns take too narrow a view about the impact of uncertainty on the usefulness of quantification data. The use of quantification data to determine aggregate methane emissions over a covered area of oil and gas infrastructure is scientifically robust, as numerous peer-reviewed scientific papers have demonstrated in recent years. And despite a degree of uncertainty, innovative LDAR technologies can still quantify methane super-emitters with enough accuracy to prompt immediate on-the-ground repairs and support the development of far more realistic leak emission profiles for oil and gas infrastructure.

Inaccuracy

A number of operators went even further and explicitly questioned the accuracy of the quantification data being generated by innovative LDAR technologies deployed over their operations. These operators argued that existing quantification capabilities contain serious enough technical limitations that their measurement data should effectively be viewed as inaccurate, and therefore unable to be relied upon for any purpose related to LDAR analysis or the calculation of aggregate emissions. They cited a variety of technical factors to explain their rejection of the use of quantification data and emphasized that their evaluation of innovative LDAR performance depended upon factors distinct from quantification capability.

Case Studies: Oil and Gas Operator Perspectives on Quantification Accuracy

Operator #1:

> *[The company] is evaluating methodologies to perform direct measurement of the methane emission reductions from its operations, which is not required currently by applicable regulations or adopted by the industry. To date, [the company] has been unable to perform reliable measurement of fugitive emissions due to the limited frequency of current field-wide applications and the limited spatial coverage of site-level fixed sensors. Nearly every value used to estimate emissions introduces significant statistical error, with duration of a leak having the highest level of error.*

Operator #2:

> *In summary, [the company] does not use any of these technologies to quantify emissions from its operations, as we believe they cannot accurately do so.*

These concerns about accuracy miss the point. Given the statistical distribution of the sources of methane emissions from the oil and gas sector, the most important feature of successful methane mitigation is the ability to rapidly detect, identify, and repair super-emitting methane leaks. For these applications, a high level of accuracy is not required. Operators must simply use the data to reliably distinguish large leaks above a certain threshold with relative confidence so that they can be isolated and repaired as an LDAR priority. If the relative size of emission events can be quantified with even a rough level of accuracy, those measurements can inform policy responses effectively.

Necessity of Quantification

Finally, many of the operators contended that quantification data is unnecessary to achieve their goals for methane leak mitigation, which are limited to the successful implementation of a "find and fix" LDAR approach. These operators suggested that the main value of innovative LDAR technologies is merely to widen the physical area over which LDAR surveys can be conducted in a cost-effective manner. They argued that their focus remains detecting, verifying, and repairing all methane leaks as quickly as possible. Correspondingly, quantification is superfluous to those objectives because it is not necessary to assess the size of a leak before responding to it and it is not necessary to measure aggregate methane emissions from their operations in order to reduce them.

Case Studies: Oil and Gas Operator Perspectives on Quantification Utility

Operator #1:

> *Importantly, [the company's] LDAR program is intended to effectively identify fugitive methane emissions and mitigate them even in the absence of quantification; currently, the program is neither designed for, nor capable of, accurately measuring those emissions.*

Operator #2:

> *The main objective with these technology pilots is to expeditiously identify, investigate and repair leaks associated with malfunctions and abnormal operating conditions that could indicate a possible exceedance of regulatory or permit conditions, resulting in faster emissions mitigation. At this time, [the company] does not believe that any of these technologies can provide quantification of emissions. Further, we do not use any of these methods to quantify and/or report emissions of methane. It is possible that advances in these technologies may ultimately result in better quantification over time, but our focus remains on detection and repair as the means to mitigate methane emissions.*

The concerns expressed by oil and gas companies about the necessity of quantification as a part of their methane mitigation activities take a far too limited view of the challenges inherent to reducing methane emissions. LDAR programs that treat all methane leaks equally are not properly designed to achieve rapid emissions reductions. The one-size-fits-all approach to leaks represents an imprudent approach to LDAR, which should prioritize the largest, super-emitting leaks that help to drive sector-wide methane emissions.

Quantification is one of the most powerful tools available to oil and gas companies to inform targeted, focused strategies to cut methane leak emissions. It is essential for developing more detailed and accurate leak emission profiles for different aspects of oil and gas infrastructure, which can reveal the emission sources and circumstances that produce a higher risk of super-emitting leaks. It is essential for identifying operational changes that can eliminate the common causes of super-emitters before such leaks occur. It is essential for implementing targeted LDAR procedures for super-emitters so that such leaks can be identified, categorized, and repaired as expeditiously as possible. Finally, it is essential for gauging the progress that oil and gas companies are making in achieving methane emissions reductions by providing accurate comparative data over long periods of time.

If the oil and gas sector does not quickly reverse course and aggressively integrate quantification data into its approach to reducing operational methane emissions, the consequences will be profound. The sector's resistance to quantification is not supported by science. Quantification is ready, right now, to serve as a vital tool in the methane mitigation toolbox.

Refining Methods for Quantifying Aggregate Methane Emissions

One legitimate challenge for oil and gas companies in quantifying aggregate methane emissions from their operations is the need for complex statistical analysis to turn a set of individual measurements into an overall emissions profile. While the scientific community has made considerable strides in recent years to develop methodologies for estimating methane emissions based upon survey measurement data, these methodologies continue to be refined and require a great deal of statistical expertise to carry out. A few of the largest oil and gas companies may have sufficient scientific and technical resources to perform these analyses based on the quantification data already in their possession. But many operators may require technical assistance to translate the quantification data from innovative LDAR technologies into a broader estimate of the total methane emissions from their facilities and equipment.

Valuable efforts are underway to refine and standardize methodologies for utilizing individual measurements to see the bigger picture of oil and gas sector methane emissions. In 2020, the United Nations Environment Programme (UNEP) and Climate and Clean Air Coalition (CCAC) issued the Oil and Gas Methane Partnership (OGMP) 2.0 Framework, a voluntary methane reporting framework for the oil and gas sector that is designed to serve as an international "'gold standard' for methane emissions reporting and performance."[50] In order to adhere to the OGMP 2.0 Framework, participating oil and gas companies are called upon to implement increasingly rigorous and comprehensive quantitative methods for site-level measurement, and to attempt to reconcile different methane emissions estimates using measurement data.[51] These activities are essential, but they can be technically challenging for oil and gas operators without sufficient internal statistical expertise. Technical and methodological challenges represent an area where further Federal research and support for the oil and gas sector could facilitate the use of quantification data in estimating aggregate methane emissions.

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[50] United Nations Environment Programme and Climate and Clean Air Coalition, "Oil and Gas Methane Partnership 2.0." Nov. 2020, accessed here: https://www.ogmpartnership.com/.
[51] *Id*.

Finding #3: Oil and Gas Companies Are Deploying Innovative LDAR Technologies in a Limited and Inconsistent Manner

Overview

The Committee has determined that the oil and gas sector is deploying innovative LDAR technologies too slowly and too inconsistently. The Committee staff welcome the recent actions by many oil and gas companies to initiate voluntary pilot programs to evaluate innovative LDAR technologies. But most of these pilots are too narrow in scope to achieve real methane emissions reductions, and there is no guarantee that temporary pilots will lead to permanent universal deployments. Additionally, the oil and gas sector's approach to innovative LDAR technologies lacks consistency, with substantial differences among operators regarding the performance metrics and standards used to assess the capability and suitability of different technologies. Different operators should have the flexibility to adapt innovative LDAR capabilities to their distinctive operational profile. But the lack of consensus in the sector about a framework for evaluating innovative LDAR technologies is an obstacle to their widespread and timely adoption. The oil and gas sector's reticence to prioritize the deployment of innovative LDAR technologies at scale does not reflect the urgency of the moment and the need to achieve rapid methane emission reductions.

Innovative LDAR Deployments and Pilots

The ten oil and gas operators provided detailed descriptions of the innovative LDAR technologies previously or currently being piloted or scaled up within their Permian operations since 2016. All ten operators asserted that they currently use at least one innovative LDAR technology to detect methane leaks within their operations. A summary of operator responses can be found in Appendix I at the end of this report. [52]

Recent years have witnessed a considerable amount of activity regarding the deployment of innovative LDAR technologies in the Permian Basin. Across all operators, over 40 innovative LDAR technologies were piloted on some level. But these pilots have resulted in at most ten permanent deployments, with at most six being implemented comprehensively or planned to do so. While pilot programs are important for operators to determine which platform produces the most useful data and which may be cost effective, they do not result in significant emissions reductions. The heavy emphasis on pilot-phase projects means that oil and gas company implementation of innovative LDAR technology remains in a relatively nascent stage.

In 2021 and 2022, several companies scaled up the deployment of certain technologies – mostly aerial surveys – to encompass their entire basin-wide infrastructure in the Permian. The Committee staff recognize that these deployments are voluntary, and we are encouraged by the

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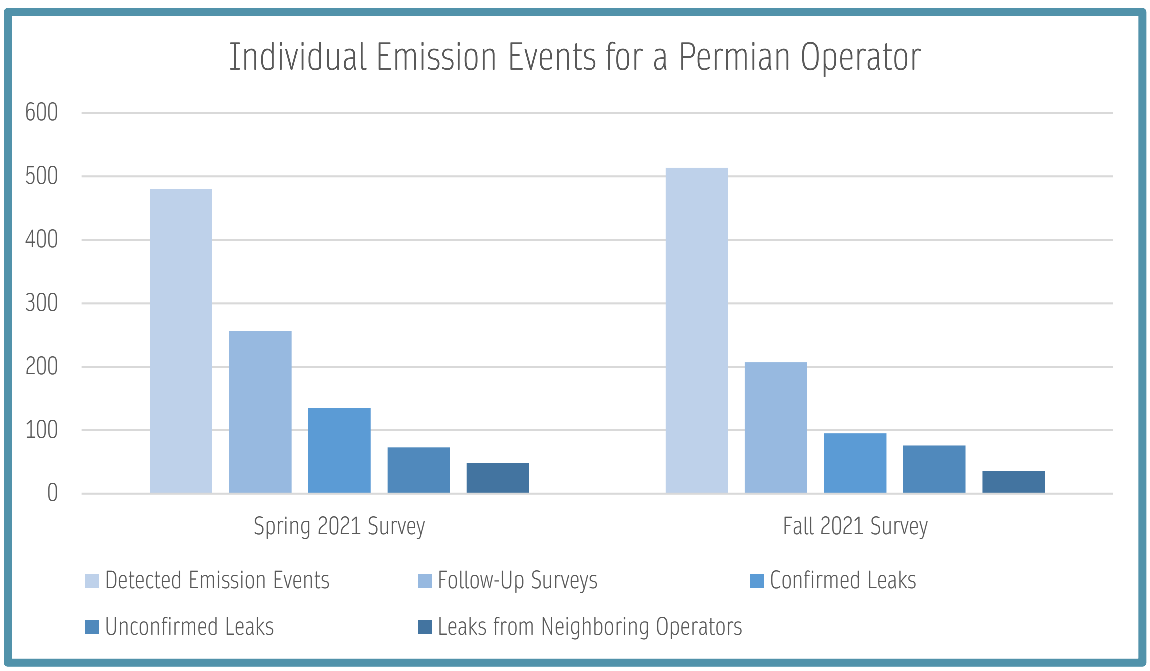
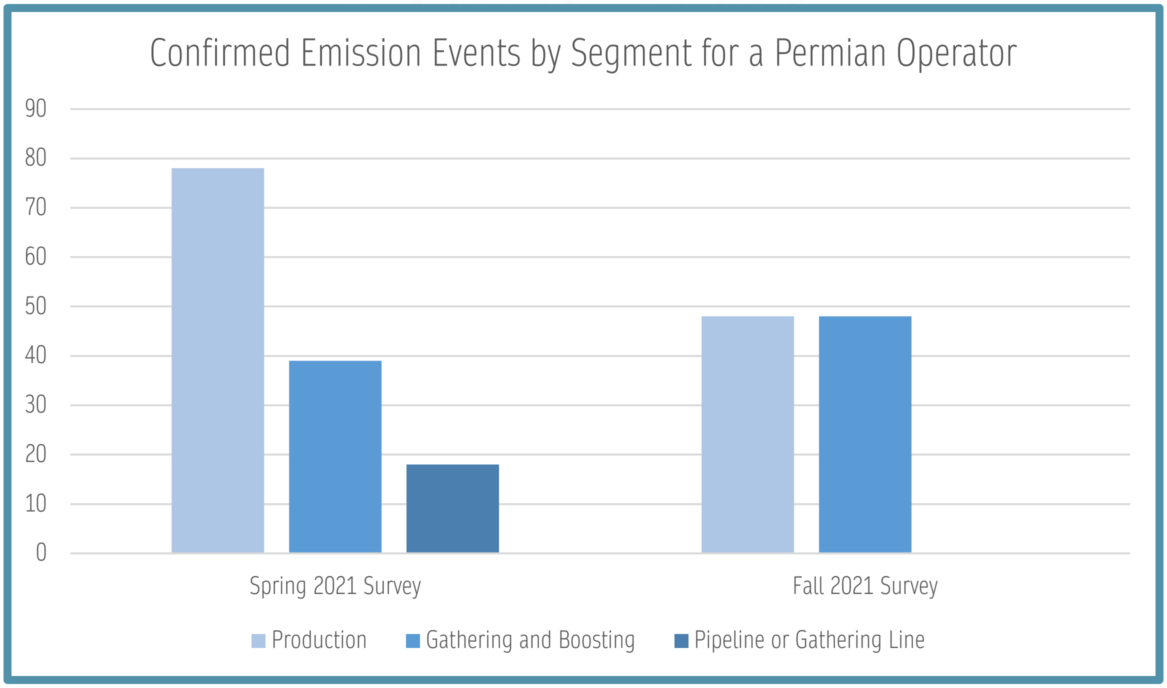
[52] In addition to their own unique innovative LDAR deployments, a number of operators noted their participation in two multi-operator pilot projects in the Permian: Project Astra and Project Falcon. Project Astra is currently assessing the effectiveness and methodology for shared networks of fixed methane emission monitors between operators. Project Falcon is currently evaluating the effectiveness of ground-based, continuous monitoring sensors at the facility level. Due to their experimental nature and limited scope for each operator, we do not include them as "deployments" by individual operators for the purposes of this analysis.

willingness of oil and gas companies to shift in this direction. But the scale of technology deployments largely remained constant during the entire period reviewed by the Committee between 2016 and 2022, notwithstanding the commercial debut of many new innovative LDAR technologies over those years. Moreover, large oil and gas companies appear to be deploying more quickly than the much wider group of small operators in the sector, who may not have the resources to invest in innovative LDAR methods.

While the need to evaluate the effectiveness of innovative technologies before adopting them is certainly justified, the pace of the transition from pilot to comprehensive deployment is incompatible with the need for the sector to align its performance with the nation's methane targets over the next decade. So long as the large majority of operator actions on innovative LDAR implementation stop at the pilot phase, the resources directed towards innovative LDAR will not have a significant environmental impact.

Innovative LDAR data reviewed by the Committee staff underscore the great promise of these technologies for methane leak mitigation. For example, one operator provided summary data for the results of two basin-wide aerial detection surveys conducted in the spring and fall of 2021. The data, broken down by individual emission events and the supply chain segments where the events occurred, demonstrates the breadth at which such technologies can operate when they are deployed at scale.





While this data is limited to one operator over the course of two aerial surveys, it suggests that innovative LDAR technologies have a high detection rate and great potential to support prompt leak repairs. Both aerial surveys detected around 500 emission events in a short period of time, leading to the rapid repair of 135 methane leaks after the spring survey and 95 methane leaks after the fall survey. The surveys detected dozens of leaks at facilities owned by neighboring operators, who were subsequently notified. The surveys detected potentially intermittent leaks that could not be repaired in an initial follow-up OGI survey but were nevertheless documented by the operator for additional surveys in the near future. The surveys also provided insights into the sources of methane leaks, highlighting the prevalence of leaks in the production segment, which accounted for 58% of confirmed leaks in the spring survey and 50% of confirmed leaks in the fall survey. Finally, the surveys demonstrated especially promising success regarding methane leaks from pipelines and gathering lines. The aerial survey found 18 leaks in the spring survey and made repairs. The survey conducted the following fall did not identify a single leak.

"More frequent awareness… could be costly": A Thwarted Innovative LDAR Deployment

The perils of limiting innovative LDAR deployments to the pilot stage were illustrated by a pilot demonstration that was conducted by one of the ten operators in the Permian Basin in 2017. The Committee staff reviewed the operator's internal summary report of the pilot demonstration. The operator's perspective on the technology makes it clear that for oil and gas companies, success can be a riskier prospect than failure.

This operator commissioned a technology research unit to evaluate the capabilities, operational quality, and cost-effectiveness of an innovative fixed-sensor methane detection technology. Between March and June of 2017, the research team field tested the technology in various conditions. Based upon the results of those tests, the research team praised the technology's capabilities and highlighted its potential value to the company in a formal report and presentation. The research team noted that:

- The technology "consistently met [the vendor's] claims regarding performance of hydrocarbon gas detection for methane and natural gas."
- The potential benefits of the technology's adoption for the company included reduced vehicle safety incidents, reduced exposures to dangerous hydrocarbons, improved environmental performance in terms of methane leaks, and decreased asset loss and damage to company infrastructure.
- There was a leak during the pilot demonstration due to an incorrectly installed vacuum breaker. Because the technology was deployed at the site, not only was the leak spotted immediately and repaired quickly, but operational personnel subsequently reported that "if the [technology] had not alerted them of the error, the issue would've likely persisted for weeks before it was identified and remedied."
- The innovative technology provided "more frequent coverage with a height advantage" than traditional OGI surveys used for regulatory compliance.
- The innovative technology was "economically viable" and would reach the cost "breakeven" point for the company in less than three years.

The research team explicitly endorsed the technology's permanent deployment by the company. It noted, "at the conclusion of the project, the team recommended adoption of the technology as the validated business drivers are expected to provide economic value as well as intangible benefits which will be quantified more fully over time."

Yet the operator's management team ultimately rejected the permanent deployment of the innovative LDAR technology. A clue as to why may be found in the report itself. Towards the end of its analysis, the research team identified two "near-term risks" to deploying the technology:

- "Government or public obtains information without understanding or correct interpretation of visuals"
- "More frequent awareness of gas emissions and leaks could lead to more action, which could be costly"

The point is brutally clear. The operator's technology experts were warning that the technology's biggest risk was not that it would fail, but rather that it would succeed – and in doing so, would find more methane leaks that the operator would then be responsible for, with all of the accompanying repair costs and reputational risks that might ensue. Enhanced methane detection would be cost-effective, would improve safety, would improve environmental performance – but it would also create a more accurate record of the operator's leak performance that would demand a response and could be damaging with the public if it became known. The fact that the innovative LDAR technology could detect methane leaks more effectively than traditional LDAR techniques was a factor that weighed *against* its adoption. Simply put, it would be safer for the operator to avoid finding more methane leaks than absolutely necessary.

By articulating these risks, this operator's research team captured a certain narrow viewpoint about the company's self-interest. The team itself did not consider these risks to be significant enough to outweigh the benefits of the technology. According to documents reviewed by the Committee staff, the research team was still arguing internally in favor of the technology's adoption as late as September 2017, months after the conclusion of the pilot demonstration, and the team supported an "adoption plan" to deploy the technology in high priority areas. But the operator clearly found the risks of the technology more compelling than the benefits. The company abandoned the use of the innovative LDAR technology after 2017, never deploying it on a broader scale or a permanent basis. In its response to Chairwoman Johnson, the company cited the complexity of "data management infrastructure" and the need for more research into "data management approaches" as its rationale for discontinuing the use of the technology. But the research team did not articulate any such concerns. Within the company, a decision was apparently made that it was better not to find too many methane leaks, whatever the consequences for the environment and climate.

Limited Tempo and Frequency of Innovative LDAR Deployments

Aerial detection surveys are the sensor platform that oil and gas companies appear closest to deploying broadly across their operations. Committee staff applaud those operators who have already started or plan to start conducting aerial surveys over their entire basin-wide operations in the Permian in 2022. However, the full emission mitigation potential of aerial surveys is not achieved unless the frequency of surveys is sufficient. Aerial detection surveys provide a snapshot in time for methane leaks, which are highly irregular and unpredictable. More frequent aerial surveys, therefore, are required to achieve greater emission reductions. Only one operator – Pioneer Natural Resources – told the Committee that it planned to conduct three or more aerial surveys annually over its Permian operations, while other operators described a commitment to less frequent semiannual surveys or stated that they had not yet determined the frequency of their planned aerial surveys. Operators should strive to conduct as many comprehensive aerial surveys on an annual basis as can practically be achieved.

It is also concerning that the deployment of ground-based fixed sensor systems – many of which have continuous monitoring capabilities – appears to be occurring at a slow pace. Unlike periodic and on-demand surveys, continuous monitoring systems can rapidly detect and identify intermittent leaks, including intermittent super-emitters. The challenge of intermittency, while it can be addressed in limited fashion through other innovative LDAR technologies, is best suited to a continuous monitoring approach, which can distinguish intermittent leak sources in real time despite their randomness and unpredictability. But the results of this investigation indicate that very few operators are prepared to scale up their deployments of ground-based continuous monitoring systems in the near future. While Mewbourne Oil stated that it is poised to do so, the other nine operators all remain in various stages of pilots, limited deployments, or no consideration at all of continuous monitoring technologies. It is unfortunate that the pace of adoption of continuous monitoring technologies does not appear to parallel other innovative LDAR technologies.

Case Study: An Operator's Analysis of Continuous Monitoring Capabilities

The Committee staff reviewed information provided by one of the ten operators regarding the company's internal analysis of innovative LDAR capabilities. This operator's research team tested six ground-based, fixed sensor LDAR technologies concurrently, all of which possessed at least some continuous monitoring capability.

The operator found promise in all six technologies, despite certain limitations. Three of the six technologies were already mature at detecting methane emissions; five of the technologies approached or achieved full continuous monitoring for emissions; five of the technologies were cost-effective for the operator; all six of the technologies were able to pinpoint the source of methane leaks with at least some degree of effectiveness; and four of the six technologies were able to quantify the size of methane leaks.

While further research and development will allow these continuous monitoring technologies to reach full maturity in the years to come, these test results illustrate that many of the technologies are ready to be adopted and deployed broadly now. Continuous monitoring at scale is realistic and achievable under current circumstances.

Absence of Integrated Multi-Tier Innovative LDAR Systems

None of the operators revealed any intention to develop an integrated multi-tier innovative LDAR approach. In conversations with Committee staff, multiple experts argued that different types of innovative LDAR technologies carry distinct strengths and weaknesses that make them better suited for some aspects of methane leak mitigation than others. For example, satellite systems have the greatest geographic reach, but the lowest resolution. Drones have considerable locational precision, but they are difficult to scale comprehensively. As a result, the preferred approach for oil and gas sector operations in the long term may be to incorporate different innovative LDAR technologies into an integrated system that utilizes different tiers of monitoring, detection, and quantification to enhance emission detection, reduce uncertainty, and accelerate the timeline to pinpoint and repair large methane leaks. At this time, neither industry nor government has established a comprehensive model for integrating disparate data sources on methane leaks while avoiding duplication. As such, a multi-tier LDAR program could be a difficult technical undertaking for any operator. But it is important nevertheless for the oil and gas sector to evaluate the feasibility of such an approach, given its potential to achieve dramatic reductions in operational methane emissions by maximizing the impact of the diverse range of innovative LDAR technologies available today. The absence of even early-stage consideration of multi-tier LDAR strategies on the part of the operators fails to recognize the potential benefits of the approach.

Multi-Tier LDAR Framework: A Model

An effective multi-tier integrated LDAR system could leverage the relative strengths of different technologies to identify and locate methane emissions.

- Ground-based fixed sensors deployed in areas of dense oil and gas infrastructure could monitor continuously and achieve the rapid detection of methane leaks
- Drones could be deployed to isolate emission sources
- Aerial surveys could periodically monitor vast geographic expanses and remote facilities
- Satellite monitoring could quickly alert operators to the largest super-emitting leaks
- Quantification data from each platform could be compared and analyzed to reduce the uncertainty and improve the accuracy of operator estimates regarding aggregate methane emissions from their operations.

Inconsistent Performance Metrics for Innovative LDAR Technologies

The ten operators also provided information regarding their frameworks for evaluating the performance of innovative LDAR technologies. Across the seven operators that provided substantive answers on their innovative LDAR technology evaluation methods, there were dozens of distinct criteria. Three operators provided no clear evaluation methods or criteria in response to the Committee's question. The metrics described by operators largely fell into the categories of:

- Spatial resolution and precision
- Accuracy and reliability
- The technology's performance in different environmental conditions
- Ease of operation
- Cost
- Leak classification
- Platform functionality

Two operators said they compare innovative LDAR technologies holistically to traditional LDAR methods.

Case Study: Disparate Evaluation Metrics for Innovative LDAR Performance

Two anonymized quotes from operator responses serve to illustrate the range of operator sophistication regarding innovative LDAR evaluation criteria. One operator currently uses no consistent set of evaluation criteria:

> *"At this time, [OPERATOR] has not developed a framework to assess performance."*

By contrast, another operator has developed a detailed evaluation framework, comprising six specific metrics. For example:

> *"File formats that are easily filtered and shared with operations..."*
>
> *"... day-rates [that] are amortized over the number of sites visited in a pilot test to develop comparable cost estimates between technologies."*
>
> *"For our operations in the Permian, we have found technologies that can detect emissions at 10 kilograms per hour to be operationally useful to identify emission sources."*
>
> *"[OPERATOR] has a focus on reducing vehicle traffic to contribute to road safety in the Permian. Leak detection solutions that do not require vehicle-based travel for site access receive additional prioritization."*

While each operator must prioritize its own objectives in selecting a suite of LDAR technologies, the lack of broad consensus on the discrete performance standards that can be used to inform innovative LDAR decisions means that each individual operator is left to their own devices when deciding which technologies would be most effective in mitigating methane leaks. This is true when assessing the accuracy of a given technology, and also when determining which technology best meets the operator's unique requirements and vulnerabilities. Companies large and small, companies with vastly different levels of resources, companies requiring different levels of technical assistance, companies confronting different geographic requirements – all must develop their own metrics to appraise the large array of innovative LDAR technologies that are now available on the market. While the lack of a broad industry consensus is no excuse for any individual oil and gas company to act slowly, it is a contributing factor to the sector's general reluctance to rapidly scale up the use of these technologies and reduce their emissions.

One answer to this problem would be for the oil and gas sector to develop its own set of best practices and standards for the performance assessment of innovative LDAR technologies. But the Committee staff confirmed that an industry-wide set of best practices to assist operators in evaluating innovative LDAR technologies does not exist. Best practices could support operators in assessing the accuracy and reliability of different LDAR technologies, overcoming the technical challenges associated with incorporating those technologies into their existing LDAR programs, and maximizing the impact of selected technologies once deployed. Best practices could also provide a sound methodology for operators to select the technologies most suitable for their operations and scale them appropriately. Industry-wide best practices could play an important role in accelerating the pace of widespread deployments for technologies with critical capabilities in reducing methane emissions from oil and gas operations.

Insights From Comparing Innovative LDAR Quantification Data with GHGRP Data

Oil and gas companies in the United States report data on their methane emissions to the EPA's Greenhouse Gas Reporting Program (GHGRP). The GHGRP requires the oil and gas sector, as well as a host of other industries, to report greenhouse gas emissions (GHG) data from large sources.[53] Reporting is required at the "facility level" except for certain suppliers of fossil fuels and industrial greenhouse gases. About 8,000 facilities across the U.S. are covered by the GHGRP. EPA presents GHGRP information through its public Facility Level Information on Greenhouse Gases Tool (FLIGHT).[54] Methane emissions are presented in metric tons of CO2-equivalent / year. Consistent with the Intergovernmental Panel on Climate Change's Fourth Assessment Report, EPA uses a factor of 25 to convert the global warming potential of methane into a CO2 equivalent. Thus, one ton of CH4 is equal to 25 tons of CO2e under the existing methodology used by EPA.

How EPA defines a "facility" in the GHGRP varies according to what type of equipment is being evaluated.[55] For some types of upstream and midstream oil and gas infrastructure, a single, specific site is considered a facility. These include natural gas-fired power plants, processing plants, transmission stations, refineries, LNG facilities, and storage facilities. But for the category of Onshore Oil and Gas Production, (e.g. wells), GHGRP presents the aggregate GHG emissions for all of the emissions reported by each operator from all of their producing assets across the entire basin. Occidental Petroleum, for example, reported it had 14,929 wellheads in the Permian Basin. It claimed 2,107,191 metric tons CO2e total methane emissions from these wellheads and other onshore oil and gas production in the Permian Basin for calendar year 2020. Similarly, emissions coming from the assets under the Onshore Oil and Gas Boosting category, which includes gathering pipelines and some compressor stations, are presented on a basin-wide basis for each operator. Pioneer Natural Resources, for example, reported 441,369 metric tons of CO2e of aggregate methane emissions from oil and gas boosting in the Permian in 2020.

Since none of the oil and gas companies the Committee surveyed have yet deployed comprehensive continuous monitoring programs to track leaks over time, it is difficult to know how long any given methane leak has existed before being detected and remediated. Under the EPA's current regulatory framework, however, oil and gas operators are required to survey their facilities for leaks twice a year. Companies use the survey data they gather from this regulatory requirement to identify and target leaks for remediation.[56] By assuming that leaks are uniformly distributed under these conditions, researchers and industry alike frequently use an average duration of three months to estimate the lifetime of a leak from start to finish.

[53] Large sources are those that emit greater than 25,000 MTCO2/year. 40 CFR § 98; Environmental Protection Agency. "Learn About the Greenhouse Gas Reporting Program (GHGRP)." 6 Oct. 2021, accessed here: https://www.epa.gov/ghgreporting/learn-about-greenhouse-gas-reporting-program-ghgrp.
[54] Environmental Protection Agency. "Facility Level Information on GreenHouse Gases Tool (FLIGHT)." Accessed here: https://ghgdata.epa.gov/ghgp/main.do.
[55] For more discussion about how EPA has considered defining "facility" for the oil and gas sector, see: Environmental Protection Agency. "Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry." *Technical Support Document*, May 2015, accessed here: https://www.epa.gov/sites/default/files/2015-05/documents/subpart-w_tsd.pdf.
[56] 40 CFR § 60.OOOOa. Accessed here: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-OOOOa.

By converting emission rates into units used by GHGRP, Committee staff compared the methane quantification data from detection surveys conducted for the operators and the emission factor-based methane data that those operators reported to the GHGRP.

Comparing Innovative LDAR Survey Data with GHGRP Data: Company A

Company A produced to the Committee survey data from an innovative LDAR methane detection survey performed in July 2021 in the Permian Basin. The survey identified 44 discrete sites which included tank batteries and wellpads. Some sites yielded multiple measurements, as the surveyor recorded emissions from individual pieces of equipment across single pads. The Company A site found to have the greatest emission intensity during this survey was a tank battery.

Permian Basin Tank Battery

Aerial image from Google Maps, May 25, 2022

The innovative LDAR company collected emissions data from five discrete pieces of equipment at the site. The equipment marked Number 5 in the image above, which appears to be a flare, registered a methane emission rate about 2.5 times higher than the 26 kg/hr rule of thumb identified by researchers to characterize a "super-emitter."[57] This particular survey did multiple passes over the same sites to establish whether a leak was persistent, and leak Number 5 at the tank battery was indeed persistent. If we assume for comparative purposes that Company A's tank battery leak emitted methane for three months before detection, **this single facility emitted a quantity of methane equivalent to 11.5% of what Company A reported to the EPA GHGRP for the entirety of its Permian oil and gas production activities in 2020.** Furthermore, if only the largest-recorded leaks detected at each of the 44 sites continued to emit at their observed rates for three months, just that small group of leaks would account for **over 40%** of the methane emissions that Company A reported to the GHGRP for its total oil and gas production activities in the Permian in 2020.

Comparing Innovative LDAR Survey Data with GHGRP Data: Company B

Company B produced to the Committee survey data from an innovative LDAR methane detection survey performed in the Permian Basin. The October 2020 survey evaluated 33 discrete sites which included wellheads, tanks, compressors, gas treaters, flares, and vapor recovery units. Of the 33 sites, seven were emitting methane at a rate higher than 26 kg/hr. The Company B site found to have the greatest emission magnitude during this survey was a compressor station. It registered an emission rate more than five-fold higher than the super-emitter threshold of 26 kg/hr. If we assume that Company B's compressor station leak persisted for three months, **this single facility emitted a quantity of methane equal to nearly 17% of what Company B reported to EPA GHGRP** for the entirety of its Permian onshore oil and gas production activities in all of 2020.

Permian Basin Compressor Station

Aerial image from Google Maps, May 25, 2022.

[57] Once again, for these calculations the Committee staff has defined a super-emitting leak as any emission event equal to or greater than 26 KG/HR and assumed a fractional methane content in the natural gas of 80%.

Furthermore, if all 33 of the sites included in this detection survey continued to leak at their observed emission rates for three months, together they would account for **over 80%** of the methane emissions that Company B reported to the GHGRP for its oil and gas production activities in the Permian in 2020.

Comparing Innovative LDAR Survey Data with GHGRP Data: Company C

Company C produced to the Committee survey data from an innovative LDAR methane detection survey of company facilities in the Permian Basin performed in February 2021. Of the 42 sites where methane emissions were detected, 18 were emitting methane at a rate greater than 26 kg/hr. The Company C site with the largest emissions magnitude was a single tank battery. It registered as emitting at a rate massively larger than 26 kg/hour. If we assume that Company C's tank battery leak persisted for three months, **this facility emitted a quantity of methane equal to over 80% of what Company C reported to the EPA GHGRP for the entirety of its onshore oil and gas production activities in the Permian in 2020.**

Permian Basin Tank Battery

Aerial image from Google Maps, May 25, 2022

Furthermore, if all 42 sites with detected methane emissions continued to leak at their observed emission rates for three months, the combined emissions of just those sites would exceed the methane emissions reported by Company C to the GHGRP for onshore oil and gas production in the entire Permian Basin in 2020 by **more than three-fold.**

To be clear, it is not known how long any of the leaks identified during these innovative LDAR surveys persisted before being detected. In addition, the innovative LDAR companies that performed these detection surveys acknowledge that their quantification data comes with some uncertainty. But due to the limitations of the LDAR practices used by the ten operators, it is entirely plausible that super-emitters such as the ones highlighted in this analysis could persist for long periods of time before being detected as part of a regulatory survey. Furthermore, there is no Federal regulatory requirement to prioritize large leaks quickly once they are identified. And the detection threshold for these technologies is low enough, and reliable enough, to detect and quantify the very large majority of methane emissions over a given area.

Companies A, B, and C each oversee enormous numbers of wellheads, pneumatic controllers, and other types of oil and gas production equipment in the Permian Basin. The opportunities for super-emitting leaks to arise are vast. These detection surveys evaluated only a snapshot in time over a portion of the infrastructure that these companies currently operate in the Permian. And yet, under reasonable assumptions, the methane leaks that were detected and quantified in these surveys would – by themselves – account for a significant percentage of the total amount of methane that the production assets of these companies are supposed to be emitting in the Permian for an entire year, or even exceed that annual amount entirely. How many more super-emitters are occurring at any given moment in such a massive area? The data reviewed by the Committee supports the view that greenhouse gas inventories maintained by the Federal government are drastically underestimating the amount of methane being emitted from domestic oil and gas operations, and that many oil and gas companies are aware of the likely discrepancy.

Recommendations for Federal Agencies

Environmental Protection Agency

A host of academic studies and the internal company methane data highlighted in this report suggest that Federal greenhouse gas inventories such as the GHGI and the GHGRP are systematically underestimating methane emissions from the oil and gas sector. But without comprehensive measurement data encompassing all of the country's major oil and gas producing regions, the methane picture will remain too out of focus for targeted policy solutions. This critical data gap can only be addressed by a coordinated effort to supplement existing methodologies for estimating oil and gas sector methane emissions with actual quantification data reflecting real-world conditions.

The Committee staff recommend a new Federal research program to conduct regular methane measurement surveys over the major oil and gas producing basins in the United States. This Methane Census program should be overseen by the EPA. The Methane Census would utilize commercially-available innovative LDAR technologies to perform large-scale methane detection surveys covering the majority of oil and gas infrastructure in each basin and to quantify the size of the detected emissions. The Methane Census would gather data to improve the characterization of oil and gas sector methane emissions in several key aspects, including by segment and by emission source, as well as data regarding the aggregate emissions for each basin. The Methane Census would provide a consistent, reliable source of comprehensive data for domestic oil and gas sector methane emissions. It would also establish a baseline against which methane mitigation policies and voluntary industry actions could be evaluated over time.

The Committee staff also recommend that EPA develop a technical study to inform approaches to reconciling the data from the Methane Census with existing EPA data sources, such as the GHGI. This technical study would evaluate how the methane data sets would interact and how they could complement each other. The technical study would also identify discrepancies between different data sets that would require further analysis, as well as the factors contributing to those discrepancies.

Finally, there is a need for the Federal government to help develop protocols that can be voluntarily applied by other entities, including private sector companies, as they use quantification data to estimate aggregate methane emissions. There are real technical challenges to translating quantification data into an operations-wide picture of methane emissions. The Committee staff recommend that EPA partner with the National Institute of Standards and Technology (NIST) to support the development of voluntary, consensus frameworks, guidelines, or technical standards for estimating aggregate methane emissions using quantification data from commercially available technologies. These technical standards should be generalizable and suitable for adoption by a variety of stakeholders, and should incorporate existing measurement capabilities where available. EPA and NIST should support the development of these consensus technical standards in consultation with the private sector and be prepared to assist private sector entities with its implementation at their request.

Department of Energy

While innovative LDAR technologies are poised to play a critical role in large-scale methane detection and quantification for oil and gas companies, this report has noted that their capabilities remain limited in certain areas. Individual methane measurements, in particular, are subject to a considerable degree of uncertainty that limits the application of quantification data for certain purposes. The improvement of quantification capabilities would allow innovative technologies to better support tailored LDAR programs and detailed methane leak analysis based upon precise measurements. It could facilitate improved methane reporting by oil and gas operators to Federal, state and local regulatory bodies. Greater technological maturity would also help address some of industry's objections to incorporating quantification data into LDAR activities.

The Department of Energy is well positioned to address capability gaps among methane detection and quantification technologies. Previous DOE research and development programs, such as ARPA-E's Methane Observation Networks with Innovative Technology to Obtain Reductions (MONITOR) program in 2014, were instrumental in developing the existing commercial market for innovative LDAR technologies.[58] The Committee staff recommend the creation of a new program at DOE specifically charged with strengthening the capabilities of methane detection and quantification technologies and addressing the sources of emission measurement uncertainty. This program should direct research investments towards the key capability limitations impacting methane quantification today, such as the influence of environmental factors like wind on quantification accuracy and the challenge of quantifying methane emissions amidst the temporal variability of methane leaks. The program should also support the advancement of data analytics processes to further improve quantification accuracy regarding emission events.

DOE is also equipped to work collaboratively with the oil and gas sector, the innovative LDAR sector and the academic community to foster engagement and support private sector proficiencies. The Committee staff recommend that DOE work with operators, innovative LDAR vendors and academic experts to develop a set of consensus best practices that oil and gas companies can use to inform their personalized decisions about which innovative LDAR technologies are best suited to their operations. These best practices would help operators evaluate the diverse array of innovative LDAR technologies currently available and consider how to incorporate them into their existing LDAR programs.

Finally, the Committee staff recommend that DOE oversee the creation of a Methane Emissions Measurement and Mitigation Research Consortium to bring together stakeholders across industry, academia, the non-profit sector, and all levels of government for the purpose of fostering closer interactions, encouraging research partnerships, and sharing information, research findings and effective LDAR approaches. The Consortium would facilitate more informed decisions about methane leaks and help inform research priorities in the Federal government and the broader scientific community. It would also build upon existing research partnerships and encourage them to continue on a more permanent basis.

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[58] Advanced Research Projects Agency – Energy. "Methane Observation Networks with Innovative Technology to Obtain Reductions." 16 Dec. 2014, accessed here: https://arpa-e.energy.gov/technologies/programs/monitor.

National Academies

Federal science agencies such as NASA, NOAA, and NIST oversee various scientific research and development programs to monitor and quantify greenhouse gases that utilize powerful measurement assets, including some assets that are set to begin operating in the coming years. The Federal government must consider to what degree any of these programs are equipped to detect methane super-emitters from the oil and gas sector and whether Federal programs and agencies can coordinate more effectively to deploy unique Federal scientific assets to improve our understanding of the scale and frequency of super-emitting leaks. The Committee staff recommend that the National Academies of Sciences, Engineering, and Medicine (NASEM) articulate a science-based strategy for the use of present and future greenhouse gas detection and monitoring capabilities, including ground-based, airborne, and space-based sensors and integration of data from other indicators, to detect methane emissions, including from super-emitters.

EPA Rulemaking: Methane Emissions from New, Modified, and Existing Sources

On November 15, 2021, EPA issued a proposed rule to strengthen the regulatory framework around methane emissions from new and modified sources in the oil and gas sector, and to directly regulate methane emissions from existing sources in the oil and gas sector for the first time.[59] The outcome of this rulemaking will likely impact technology developments for years to come. The rulemaking is not the Committee's focus, but there are opportunities to ensure the final product supports scientific innovation.

First, the Committee staff are concerned that the agency's initial treatment of innovative LDAR technologies does not reflect a technology-neutral approach. There is no single best technological approach to methane detection, quantification, and mitigation, and it is critical that EPA develop a regulatory framework that is flexible enough to incorporate novel technological capabilities that have not yet matured but will do so in the coming years. Given the wide range of innovative LDAR technologies and platforms already available on the market – aerial surveys, drones, satellites, ground-based fixed sensors – the agency's approach must allow for all different kinds of technologies to establish their efficacy, and for oil and gas companies to pursue detection technologies that best fit their needs as long as those technologies meet the agency's standards for performance validation.

In particular, it is absolutely vital that EPA's regulatory framework allows for and encourages the deployment of continuous monitoring technologies across oil and gas operations. Continuous monitoring is uniquely suited to mitigating intermittent methane leaks and targeting super-emitters rapidly. Innovative LDAR technologies with continuous monitoring capabilities should have every opportunity to demonstrate their compliance with regulatory requirements alongside other technologies.

[59] Environmental Protection Agency. "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." *Federal Register*, vol. 86, no. 217, pp. 63110-63263, 15 Nov. 2021, accessed here: https://www.federalregister.gov/d/2021-24202.

The draft rule offers a matrix framework as one potential approach to evaluating and approving innovative LDAR technologies for regulatory use, in which an LDAR technology with a lower detection threshold may satisfy regulatory requirements if it is deployed more frequently than a higher-resolution technology. This strategy appears to be promising. But EPA's initial proposal does not go far enough in recognizing the diversity of platforms and sensors that characterize innovative LDAR technologies and in particular, the opportunity to combine multiple technologies to form a comprehensive picture of an operator's emission profile. The agency should consider developing a more expansive and flexible matrix.

EPA currently uses the Alternative Means of Emission Limitation (AMEL) process to evaluate and approve new methane detection technologies for regulatory purposes. Proposed alternatives must show that they can achieve equal or greater emissions reductions relative to the existing standards. EPA should improve the AMEL process so that it is more expedient for innovative methane LDAR technologies to establish their ability to deliver methane emission reductions. LDAR technologies are improving rapidly as existing vendors enhance their offerings and new ones enter the market. A more workable AMEL process that reflects the pace of innovation will ensure greater accuracy, precision, frequency, and breadth of coverage. It will also enable more flexibility for oil and gas operators to select from a range of high-quality LDAR systems according to their own criteria.

Finally, the Committee staff urge EPA to implement a formal framework allowing third parties, including local communities, to report methane leaks to the agency for investigation by oil and gas operators. The maturation of innovative LDAR technologies has made it possible for third party actors to play an important role in oversight of oil and gas sector methane emissions. They can offer a valuable check on data being reported by operators and help ensure that the communities most impacted by localized emissions can contribute to the protection of their own health and safety.

Opportunities for Industry

Oil and gas companies need not wait for further Federal action before aggressively confronting methane leaks from their operations. There are simple, tangible steps that operators can take immediately to reduce methane emissions and increase transparency, entirely independent of any legislative or regulatory policies at the Federal level.

As a first step, there is a valuable opportunity for U.S. oil and gas companies to join the Oil and Gas Methane Partnership 2.0 (OGMP 2.0) Framework. As mentioned previously, this United Nations-sponsored collaboration between environmental groups, governmental organizations, and industry represents the gold standard for transparent, rigorous methane emissions reporting by the oil and gas sector. The OGMP 2.0 Framework provides an advanced methodology for companies to report their methane emissions and calls for the enhanced use of measurement techniques in methane reporting, while setting clear guidelines regarding how companies can adhere to the Framework and align their reporting methods with its best practices. The emission data reported by participating member companies is not disclosed publicly, but it will serve as an important data source for the International Methane Emissions Observatory (IMEO), a new joint UN-European Union initiative to improve understanding of global atmospheric methane levels.[60] Companies that join OGMP 2.0 can thus support global methane science in addition to showcasing greater transparency regarding their methane footprint.

Joining OGMP 2.0 would not impose any additional regulatory burdens on operators. It has minimal costs and clear benefits, both for companies and for the scientific community. Large oil and gas companies from all across the world have joined OGMP 2.0, including BP, Shell, and Total, but participation from U.S. oil and gas companies has noticeably lagged behind their European and international counterparts. Of the ten operators that provided information to the Committee, only Occidental Petroleum has committed to the OGMP 2.0 Framework. The Committee staff commend Occidental for making this voluntary commitment to greater transparency and rigor in its methane reporting. There is no reason why the other nine operators should not do the same if they wish to fully confront their methane emissions. Given that joining the OGMP 2.0 Framework is entirely voluntary and can be done at any time, oil and gas companies that decline to do so will face inevitable questions about their level of commitment to reducing methane emissions and whether they will be prepared to take further necessary actions in the future.

Oil and gas companies also have an opportunity to accelerate the pace of their deployment of innovative LDAR technologies. The oil and gas sector is moving too slowly and too inconsistently to deploy methane detection and quantification technologies at scale within their operations. Too many technologies remain in pilot phase limited deployments despite their emission reduction potential, which has been adequately demonstrated through controlled testing and peer deployments among other companies. Operators can move aggressively beyond pilot evaluations and towards full-scale deployments designed to achieve widespread emission reductions.

[60] United Nations Environment Programme. "Methane." Accessed here: https://www.unep.org/explore-topics/energy/what-we-do/methane.

Finally, oil and gas companies have an opportunity to adopt LDAR strategies and practices that are informed by the most up-to-date scientific research on oil and gas methane emissions. Companies can prioritize the rapid detection and mitigation of super-emitting leaks by defining, identifying, tracking, and characterizing super-emitters, and by designing and equipping their LDAR programs to target them. Companies can embrace the role of quantification as a pillar of methane LDAR and incorporate quantification data into how they prioritize leak mitigation. Companies can acknowledge that not all leaks are created equal, and that the greatest environmental benefit can be gained from prioritizing the largest leaks rather than adhering to outdated mindsets. If oil and gas companies are prepared to accept the science of methane leaks and act on it, the magnitude of benefits for the environment and the sector itself will be immense.

Appendix I: Permian Basin Innovative LDAR Deployments by Operator, 2016-Present

Admiral Permian Resources			
Technology	Status	Scope	Future Commitments
Ground-based continuous monitoring (1)	Ongoing	Pilot, limited scope	No Commitment

Ameredev			
Technology	Status	Scope	Future Commitments
Ground-based continuous monitoring (1)	Ongoing	Pilot, limited scope	No Commitment

Chevron			
Technology	Status	Scope	Future Commitments
Aerial survey (2)	Ongoing	Pilots, limited scope	1 platform selected for Comprehensive Permanent Deployment
Ground-based continuous monitoring (1)	Terminated	Pilot, limited scope	None
Drone survey (1)	Terminated	Pilot, limited scope	None

ConocoPhillips			
Technology	Status	Scope	Future Commitments
Aerial survey (1)	Terminated	Pilot, limited scope	None
Satellite survey (1)	Terminated	Pilot, limited scope	None
Helicopter survey (1)	Ongoing	Pilot, limited scope	No Commitment
Ground-based continuous monitoring (6)	Ongoing	Pilots, limited scope	1 platform selected for limited Permanent Deployment

Coterra Energy			
Technology	Status	Scope	Future Commitments
Aerial survey (2)	Ongoing (1)	Deployed comprehensively (1)	1 platform selected for Comprehensive Permanent Deployment on semiannual basis
	Terminated (1)	Pilot, limited scope (1)	
Ground-based continuous monitoring (3)	Ongoing (2)	Pilots, limited scope	No Commitment
	Terminated (1)		

Devon Energy			
Technology	Status	Scope	Future Commitments
Aerial survey (2)	Ongoing (1)	Deployed comprehensively (1)	1 platform selected for Comprehensive
	Terminated (1)	Pilot, limited scope (1)	

			Permanent Deployment on semiannual basis
Ground-based continuous monitoring (1)	Ongoing (1)	Pilot, limited scope	No Commitment

ExxonMobil			
Technology	Status	Scope	Future Commitments
Aerial survey (3)	Ongoing (1)	Deployed comprehensively (1)	1 platform selected for Comprehensive Permanent Deployment
	Terminated (2)		
Satellite survey (1)	Uncertain	Pilot, limited scope	No Commitment
Helicopter survey (1)	Uncertain	Pilot, limited scope	No Commitment
Drone survey (1)	Uncertain	Pilot, limited scope	No Commitment
Ground-based continuous monitoring (1)	Uncertain	Pilot, limited scope	No Commitment
Truck-mounted survey (1)	Uncertain	Pilot, limited scope	No Commitment

Mewbourne Oil			
Technology	Status	Scope	Future Commitments
Aerial survey (1)	Ongoing	Pilot, limited scope	No Commitment
Ground-based continuous monitoring (1)	Ongoing	Pilot, limited scope	1 platform selected for Comprehensive Permanent Deployment
Satellite survey (1)	Terminated	Pilot, limited scope	None

Occidental Petroleum			
Technology	Status	Scope	Future Commitments
Aerial survey (3)	Ongoing	Pilot, limited scope	Multiple platforms selected for Permanent Limited Deployment
Drone survey (1)	Ongoing	Pilot, limited scope	No Commitment
Ground-based continuous monitoring (2)	Ongoing	Pilots, limited scope	No Commitment
Satellite survey (2)	Ongoing	Pilots, limited scope	No Commitment

Pioneer Natural Resources			
Technology	Status	Scope	Future Commitments
Aerial survey (2)	Ongoing (1)	Deployed comprehensively (1)	1 platform selected for Comprehensive Permanent Deployment, three times per year
	Terminated (1)	Pilot, limited scope (1)	

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Article

Methane Emissions from Abandoned Oil and Gas Wells in California

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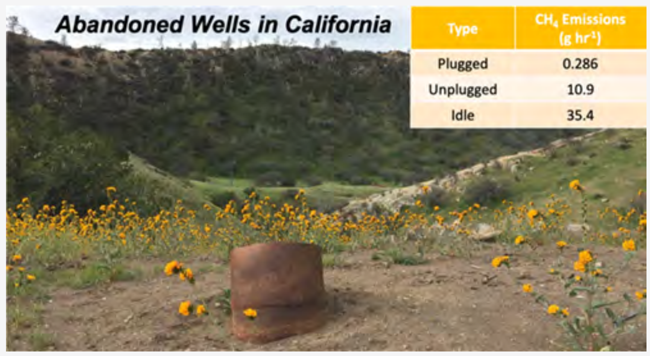
ABSTRACT: California hosts ~124,000 abandoned and plugged (AP) oil and gas wells, ~38,000 idle wells, and ~63,000 active wells, whose methane (CH_4) emissions remain largely unquantified at levels below ~2 kg CH_4 h^{-1}. We sampled 121 wells using two methods: a rapid mobile plume integration method (detection ~0.5 g CH_4 h^{-1}) and a more sensitive static flux chamber (detection ~1×10^{-6} g CH_4 h^{-1}). We measured small but detectable methane emissions from 34 of 97 AP wells (mean emission: 0.286 g CH_4 h^{-1}). In contrast, we found emissions from 11 of 17 idle wells—which are not currently producing (mean: 35.4 g CH_4 h^{-1})—4 of 6 active wells (mean: 189.7 g CH_4 h^{-1}), and one unplugged well—an open casing with no infrastructure present (10.9 g CH_4 h^{-1}). Our results support previous findings that emissions from plugged wells are low but are more substantial from idle wells. In addition, our smaller sample of active wells suggests that their reported emissions are consistent with previous studies and deserve further attention. Due to limited access, we could not measure wells in most major active oil and gas fields in California; therefore, we recommend additional data collection from all types of wells but especially active and idle wells.



INTRODUCTION

Greenhouse gas (GHG) emissions from hydrocarbon infrastructure are a major source of methane (CH_4) globally,[1] with methane alone contributing nearly one-quarter of the cumulative radiative forcing since 1750.[2] Methane has a global warming potential 86 times greater than CO_2 over 20 years and 34 times greater over 100 years.[3] In addition to climate concerns, methane leakage from wells can pose a potential risk of explosion,[4] contaminate groundwater,[5] impact air quality through the formation of ozone,[6] and be accompanied by the release of benzene, toluene, and other aromatics that affect human health.[7] Here, we focus primarily on surface methane emissions from various wells across California.

In the United States, methane monitoring regulations for the oil and gas industry on federal lands were substantially rolled back in August 2020; now, monitoring of fugitive emissions at active wells is only required to take place twice per year, with exemptions granted to low-production well sites (<15 barrels of oil equivalent per day).[8] Upon removal of the production equipment, monitoring is no longer required, potentially leaving millions of idle and abandoned wells unmonitored. However, some states further regulate methane monitoring from these wells; California requires periodic pressure testing for idle wells. Nevertheless, emissions currently reported by the industry and states' GHG inventories likely provide a lower estimate of atmospheric methane emissions because quantitative emission data are incomplete. This conclusion is supported by growing evidence of methane emissions from abandoned wells in hydrocarbon production areas in the Marcellus shale in Pennsylvania and West Virginia,[9−12] midwestern United States,[13,14] United Kingdom,[15] Netherlands,[16] and the North Sea.[17,18] The majority of methane emissions from abandoned wells investigated in the United States originated from thermogenic sources[9,10,13]—suggesting a loss of well integrity[19]—and the unintended release of deep reservoir gas may also arise via gas migration along the outside of the well as found in the North Sea[17,18] and in Alberta, Canada.[20]

Today, there are ~1.1 million active wells in the United States and ~800,000 inactive/idle wells.[21] The number of abandoned and plugged (AP) wells in the United States is unknown; various sources suggest that this number may fall between 1.6 and 3.2 million wells.[21−23] Every drilled well has the potential to be a source of methane emissions to the atmosphere through its well casing: the production annulus can serve as a conduit from deep reservoirs to the surface, and typical plugging procedures will not block this pathway.[24] Evaluating the emissions from abandoned wells is therefore important to determine if wells are acting as

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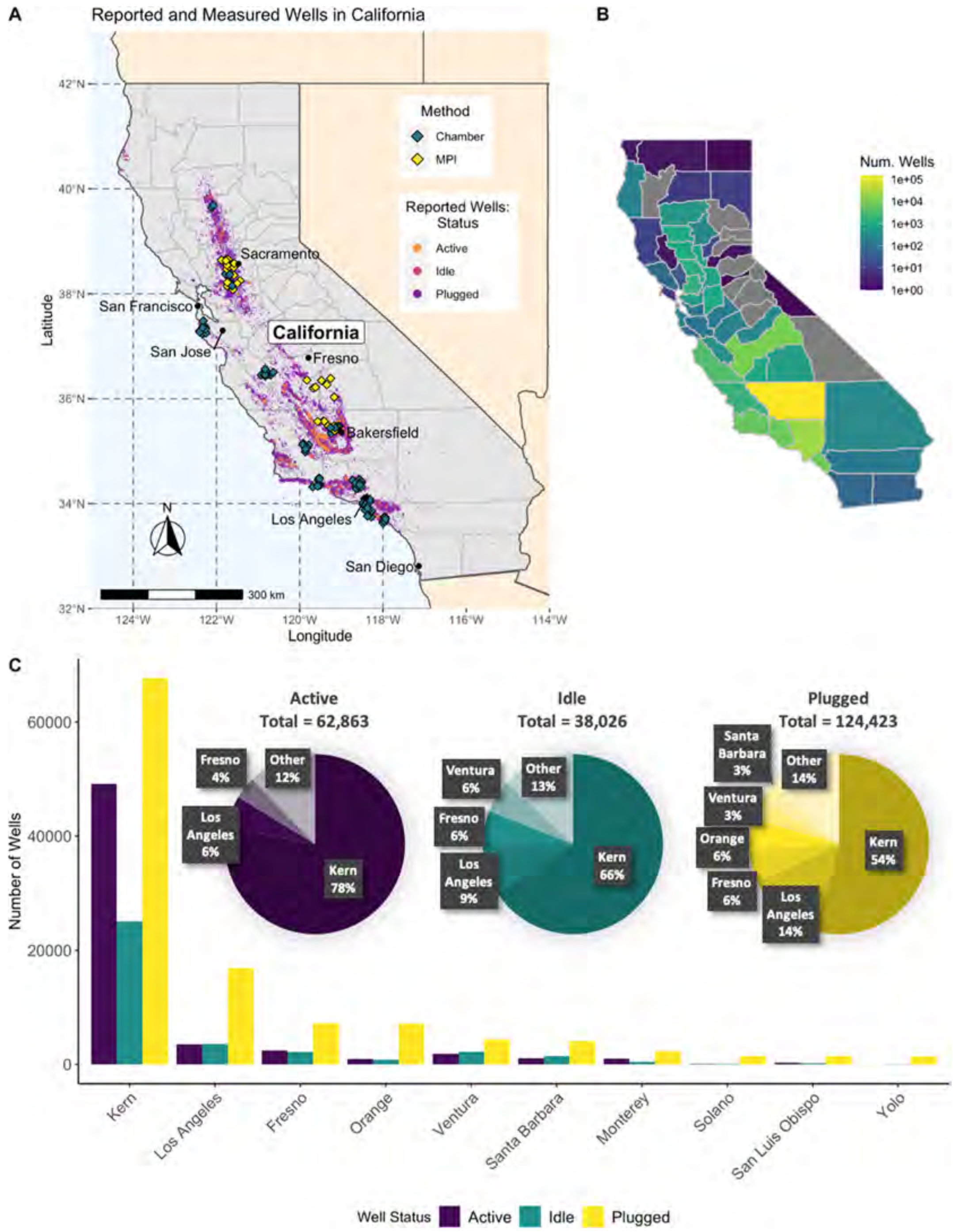

Figure 1. Distribution of wells among counties and sampling sites. (A) Distribution of known wells as reported in the CalGEM database (smallest dots) and their well status designation. Omitted are 1 abeyance well, 7551 canceled wells, 5160 new wells, and 1908 unknown wells. The 203 wells designated "plugged only" were plotted as plugged wells. The larger diamonds indicate our sampling sites in this study, denoting whether the measurement was taken using a chamber-based approach or taken using the mobile plume integrator. (B) California counties are colored based on the total number of active, idle, and plugged wells in each county. Most wells are found in the southern part of the state and in the Central Valley. (C) Total number of wells by type in the top 10 counties and the fractions of each well type in different counties. Kern County by far has the most wells of any county in the state and is home to 78, 66, and 54% of the active, idle, and plugged wells, respectively, of each well category.

conduits for the reservoir gas to reach the atmosphere and mitigate this issue where it may occur. In addition, every region faces different geography and history: well abandonment procedures varied and evolved over the 150 year oil and gas drilling history in 22 states.[25] Other geologic or environmental factors may potentially contribute to variations in integrity of long-term well abandonment methods. Thus, California and other regions should conduct quantitative evaluation efforts, rather than relying on data from other regions.

California has been a major producer of oil and natural gas for more than a century. Today, the Department of Conservation's Geologic Energy Management Division (CalGEM, formerly DOGGR) oversees operations of the oil and gas industry and maintains the records of wells in the state.[26] California currently

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Table 1. Summary Statistics[a]

status	status in CalGEM	count of measured wells	measurements: number [%] of measured wells emitting CH_4	number [%] of measured wells emitting >1 g CH_4 h^{-1}	mean (g CH_4 h^{-1}) used as emission factor	95% UCI	median (g CH_4 h^{-1})	min (g CH_4 h^{-1})	max (g CH_4 h^{-1})	total number of wells in CA
abandoned	plugged	97	34 [35%]	1 [1%]	0.286	1.64	0.0	−0.1	26	146,000[b]
	idle	17	11 [65%]	7 [41%]	35	88.5	0.4	0.0	246	38,026
	unplugged[c]	1	1 [100%]	1 [100%]	11	NA	NA	11	11	NA[c]
active	active	6	4 [67%]	4 [67%]	190	739	1.5	0.0	1100	62,863

[a]Statistics (mean, median, min, max, upper 95% confidence interval) of emissions from wells measured in this study. Wells were considered to be leaking if they were emitting at rates higher than 1 g h^{-1}. All emission units are g CH_4 h^{-1}. Not included in the total well count: 1908 unknown wells, 7551 canceled wells, 5160 new wells, and 1 abeyance well (permit pending review). AP wells include 124,423 plugged wells and 203 "plugged only" wells, where the well has been plugged but the surface not reclaimed. Total wells in CA: 233,667. [b]Adjusted in this study from 124,626, assuming a ~17% undocumented rate of AP wells by CalGEM. [c]Unplugged wells are not directly reported by CalGEM.

hosts 124,626 AP wells. Since 1974, California has had relatively strict abandonment procedures to restore the surface and prevent emissions and groundwater contamination from the wells.[27] Properly abandoned wells in California are plugged with at least 100 ft of cement at the surface, requiring additional cement plugs depending on the geologic strata that the well penetrates. The casing is cut and capped, so it is buried 5−10 ft below the ground.[28] Not all wells were properly abandoned, and although the true number of wells in this category is difficult to estimate, it includes one that we measured in this paper. We consider these wells to be "unplugged" if they have visible well casing without obvious cement plugging.

In addition to these wells, there are 38,026 idle wells in California, which the United States Environmental Protection Agency (USEPA) considers to be abandoned. Idle wells are unplugged but would not have produced oil or gas for 2 or more years.[28,29] If the owner goes bankrupt, the idle well becomes "orphaned" and the state assumes the responsibility to complete abandonment, which could take decades. In 2018, the cost to the state averaged $53,329 to abandon a single well,[30] but this cost could be offset by factoring in the social cost of the emissions if the well was left unabandoned.[31]

In California, emission inventories from oil and gas production are reported in the California GHG Inventory, prepared by the California Air Resources Board (CARB), but only include estimates of emissions from producing wells.[32] Although abandoned wells are not included in the California GHG Inventory, the state has recently passed legislation that requires idle wells to be more rigorously tested and repaired (e.g., Assembly Bill 1328, Assembly Bill 2729).[33,34] This recent legislation is driven by the state's regulations and programs (e.g., Senate Bill 32, Assembly Bill 1496) aimed at identifying major sources of methane and reducing these emissions and other GHGs to 40% below 1990 levels by 2030.[35,36]

Efforts to quantify California's emissions from wells and other sources recently included the California Methane Survey (Duren et al. 2019). They surveyed 88% of all California's methane-emitting infrastructure—including abandoned and active oil and gas wells—with a minimum detection limit of ~2 kg CH_4 h^{-1}.[37] To adequately measure emissions from wells, a much lower detection limit is needed; for instance, if the ~200,000 active and abandoned wells in California were to emit 1 kg CH_4 h^{-1}, these emissions alone would roughly equal CARB's estimate for all California methane emissions in 2019.[32]

In the following sections, we describe a combination of methods for measuring methane emissions from accessible AP, idle, and active oil and gas wells and their surrounding soil. We report measurements of methane emissions from abandoned (plugged, unplugged, and idle) wells across 14 counties in California with <1 g CH_4 h^{-1} sensitivity in order to better capture smaller emitters. We supplement these measurements with additional measurements from a smaller number of active wells, which appear to emit methane at higher rates.

METHODS

Site Selection. We used CalGEM's Well Finder database to collect information about the wells, including location, well status, drilling depth, spud, and abandonment dates.[26] Sites were chosen to promote sampling from as many oil and gas fields and geographic regions as possible; we ultimately sampled wells from 14 different counties (Figure 1A). A prominent consideration when selecting sites was logistical constraints: accessible sites for chamber measurements included sites on a public land or those with permission for access from private landowners and sites where we could feasibly and safely transport sampling equipment to the well. Chamber measurements were mostly taken on public property, with a minority of sites on private land. Sites chosen for the mobile plume integrator were either on public property or were close enough to a public road to allow emission sampling without entering private property.

We measured methane emissions from 121 wells in California, directing our focus on abandoned wells (plugged, unplugged, and idle), which receive less mandated emission monitoring. We sampled 115 abandoned wells (97 plugged, 1 unplugged, and 17 idle) and 6 active wells. Wells were measured in campaigns covering all seasons between July 2016 and March 2019. All wells were measured once, except for two to evaluate the persistence of their leaks: one abandoned unplugged well, which was measured on three different occasions and one idle well which was measured twice. Emission factors for each well type were calculated by taking the average methane emission factor from the sampled wells for each category (plugged, unplugged, idle, and active). For each estimate, the confidence interval of the mean was calculated by bootstrapping the data and using the "bias corrected and accelerated" method to calculate the 95% confidence interval (R package "boot").

Number of Wells in California. Understanding the number of wells in California is essential for scaling our statewide emissions estimate. CalGEM currently reports 124,626 AP wells, 62,863 active wells, and 38,026 idle wells (Figure 1C, Table 1). A majority of wells are found in Kern County (southern San Joaquin Valley, containing the city of

Bakersfield), with Los Angeles, Fresno, and Orange counties being other high concentration areas. While the CalGEM database is the most comprehensive listing of wells in California, it is still subject to gaps and inaccuracies. 1908 wells are described as "unknown" status. "Unplugged" wells are not specifically reported, but it is possible that some wells with the status "unknown" are unplugged. Furthermore, there are some wells that are missing entirely from this database, including some that we measured here. We found a well in the field that was unplugged with no production infrastructure, and thus, we believe that the status of "unplugged" may be important to consider.

We compared 57 wells from old maps from 1944 to 1946 to the CalGEM database to estimate how many wells may be unreported in the CalGEM database, particularly those drilled at the beginning of the 20th century. At random, we selected a well from the United States Geological Survey (USGS) map and searched for a similar well on the CalGEM database, using identifying characteristics such as lease name, American Petroleum Institute number, operator, and spud date. We marked it "reported" if we could, with reasonable certainty, identify the same well with CalGEM; otherwise, we marked it "unreported". Our USGS maps were sourced from Santa Rosa Hills, North Los Angeles, Sunset-Midway, Puente Hills, and Santa Barbara, representing the various geographic regions where drilling was occurring at this time.

Measurement Protocol. We measured methane emissions from wells using two approaches: (1) a combination of time intensive (~1 h) and highly sensitive (~1×10^{-6} g CH_4 h^{-1}) measurements that employ static flux chambers to capture all gases emitted from the enclosed footprint of each well and (2) a comparatively rapid (~10 min) but less sensitive (~0.5 g CH_4 h^{-1}) mobile plume integration (MPI) measurement of ambient air downwind of the well. These techniques are summarized in the sections below and described in more detail in the Supporting Information. Of the 121 sampled wells, 36 wells were sampled using the MPI method, while the remaining 85 were sampled using static flux chambers.

Static Flux Chamber Measurements. The methodology for the static flux chamber portion of this study is based on Kang et al. (2016),[10] with new methods developed to accommodate California's abandonment guidelines for AP oil and gas wells. A static flux chamber encompasses the footprint of the leak and is sealed to the surrounding environment. When coupled with a Picarro cavity ring down spectrometer (CRDS; G2210-i) for concentration measurements, the minimum detection limit is ~1×10^{-6} g CH_4 h^{-1}.

The flow rate is calculated by measuring the linear increase in methane concentration over time in a known volume, expressed using the following relationship

$$Q = \frac{dC}{dt} \times V \times 1,000,000 \tag{1}$$

where Q is the flow rate (in L CH_4 h^{-1}), dC is the change in methane concentration (in ppm) over the time period, dt (in hours), V is the volume of the chamber (in L), and 1,000,000 is the conversion factor for ppm. Emissions are then converted to mass flow units (g CH_4 h^{-1}) using measured air temperature at ambient pressure.

We used chambers that ranged in size from 33.8 to 32,659 L, depending on the presence and size of the surface infrastructure (Figure 2A–C, Supporting Information). For wells that were buried with no surface infrastructure, we used a cesium G-860

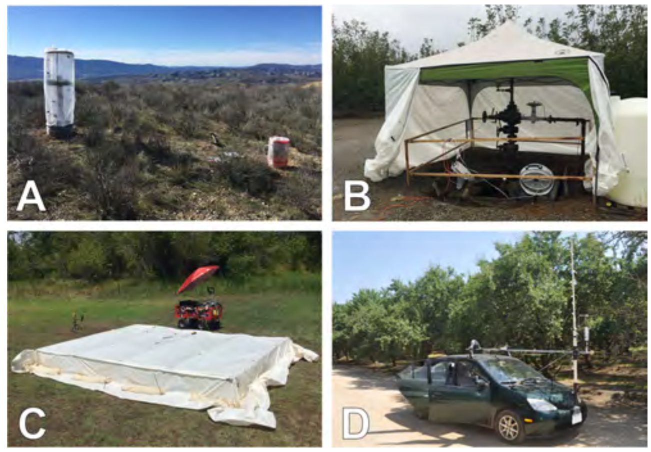

Figure 2. Sampling equipment used in this study. We used chambers of various sizes (A–C) as well as a mobile plume integrator (D) to sample methane emissions from oil and gas wells. (A) Exposed plugged wells were sampled with expandable cylindrical chambers, with the chamber fitting over the above-ground casing. (B) Idle wells required a much larger chamber to enclose all of the associated infrastructure; here, we show a 12′ × 12′ Coleman canopy modified with plastic siding. (C) Buried wells were first located within 1 m using a magnetometer (Supporting Information), and emissions were measured using a large-footprint chamber to cover the full position of the wellhead and tortuous pathways of gas movement through soils. (D) Mobile plume integrator is deployed on a car and is used to measure emissions from wells which are detectable from public roadways. The mast has 12 inlets and three Picarro CRDS analyzers in the car measure concentrations at a rate of ~1 Hz. The car is also equipped with a global positioning system (GPS) and sonic anemometer.

cesium-vapor magnetometer (Geometrics) to locate the well within 1 m (Supporting Information), similar to magnetometry work by Pekney et al. (2018).[12] Gas samples were measured either on the Picarro CRDS for methane, ethane, carbon dioxide, and $\delta^{13}C-CH_4$ or on the gas chromatograph (GC) (Agilent 6890N) for methane, ethane, propane, *n*-butane, and isobutane.

In addition to the species listed above, the one unplugged well was also measured for benzene measurements by EAG Laboratories (San Jose, CA) in January 2017. 1.5 L of sample were run across a "coconut shell charcoal" sorbent tube; the total benzene which adhered to the charcoal was measured. Discrete samples were taken over time. Given the chamber size of 204 L used to measure this well, the 30 min testing period, and that the analytical detection limit of benzene concentration using this method was ~4.2 ppb (by volume), the minimum benzene flow rate we could detect was 6 μg h^{-1}.

Laboratory testing of the chambers used in this study suggest that they are accurate in determining the flow rate within 20% error when measuring the concentrations on a GC (Agilent 6890N; injections were made using a sampling loop at constant pressure; standards 5 ppm, 10 ppm, 100 ppm, and 1%). Laboratory testing with the Picarro achieved results within 3% (Supporting Information).

Mobile Plume Integration. For this study, methane emissions from active wells were sampled exclusively using the MPI (Lawrence Berkeley National Lab). This method provides continuous roadway measurements of the vertical distribution of methane plumes, horizontal winds, and other meteorological variables to estimate emissions from localized plumes,[38] building on methods pioneered by Rella et al.[39] and conceptually similar

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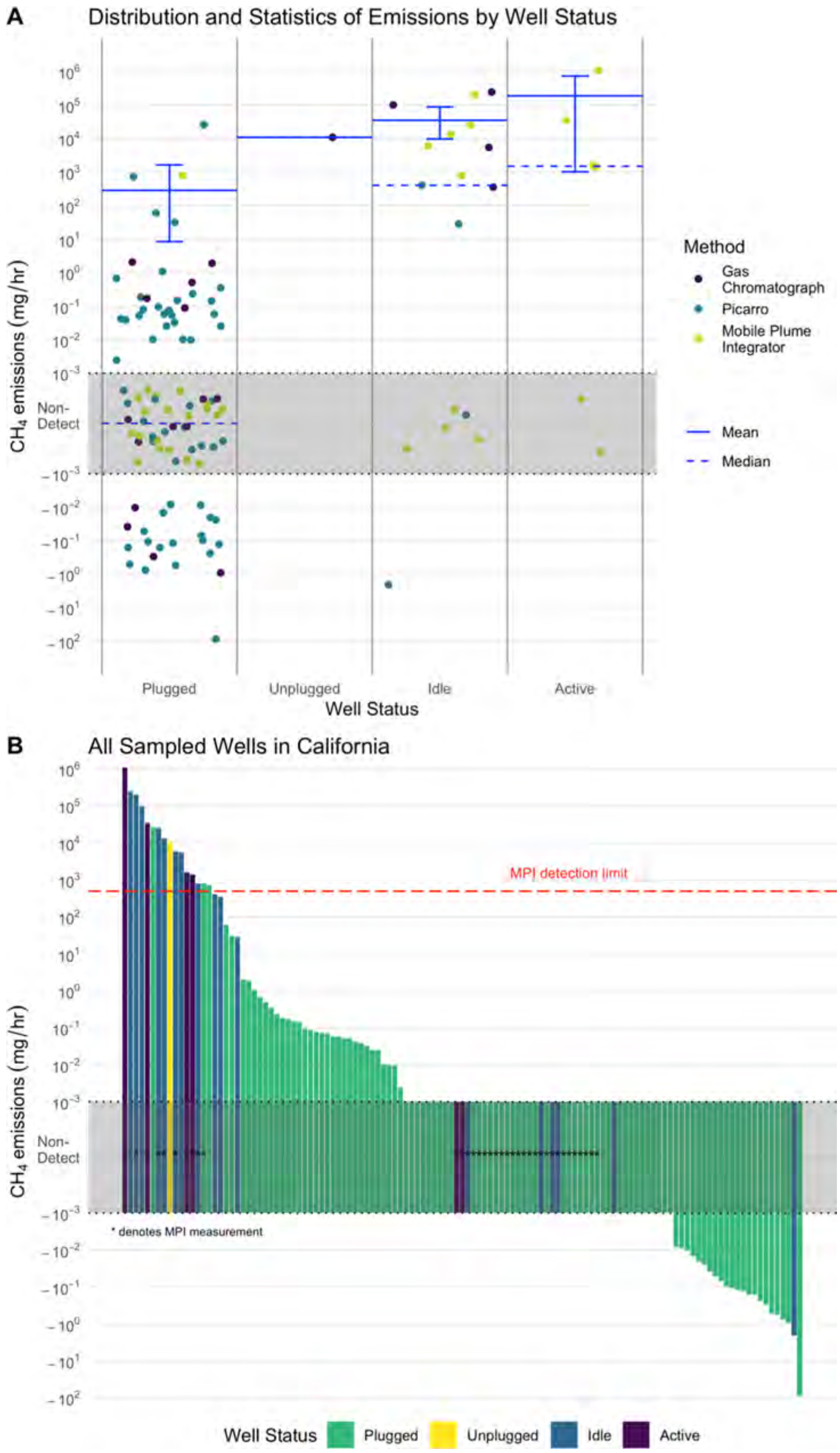

Figure 3. Ranked methane emissions by wells. (A) Each point represents an individual well measurement, colored by the method. The *y*-axis is in the log scale because emissions encompass multiple orders of magnitude. The solid blue line represents the mean measurement for each category, and the dashed blue line represents the median. The error bars are our 95% confidence interval of the mean, calculated using a bootstrap bias-corrected and accelerated method with 200,000 replicates. (B) Methane emissions from each of the sampled wells ranked by a magnitude of emissions with color-coding showing the well type. Units are mg CH_4 h^{-1}, emphasizing the sensitivity of chamber measurements with a detection limit of 10^{-3} mg CH_4 h^{-1}, as compared with the 500 mg CH_4 h^{-1} detection limit of the MPI system.

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to those of von Fischer et al.[40] The vehicle is driven through a methane plume, continuously drawing air streams from multiple (here 12) inlets spaced at 0.3 m along a 4 m mast and aggregated into three streams capturing three height intervals at roughly 0.6−1.5, 1.8−2.7, and 3−4 m above the road (Figure 2D).

Air from the three streams is then continuously measured by the three separate gas analyzers (two Picarro 2301 and one 2132), each operated at a flow (∼250 sccm) and data acquisition rate (1 Hz) sufficient to provide approximately 0.5 Hz time response. In addition, the vehicle's location, speed, and heading data are measured with a GPS (Garmin 18x), and wind velocity is measured using a sonic anemometer (RM Young 81000), with data synchronized and recorded at 1 Hz on a data logger (Campbell CR1000). More details about the calculations and field evaluation of the MPI are available in the Supporting Information (Figures S3−S5).

RESULTS AND DISCUSSION

Methane Emissions Summary. *Plugged.* Observed methane emissions were small relative to other well types for the 97 AP wells we measured across California. We detected methane emissions from 34 wells (35%), ranging from 2×10^{-6} to 26.4 g h^{-1}. The highest-emitting AP well was located in a tar pit in Los Angeles County (Figure S6) and was leaking more than an order of magnitude higher than the second highest emitter. With our nondetectable measurements assumed to be zero, the average emission factor from AP wells was 0.286 [95% CI: 0.00836, 1.64] g CH_4 h^{-1} (Figure 3A, Table 1).

Idle/Orphaned. We detected emissions from 11 of 17 (65%) idle wells that we sampled. On average, we found that idle wells emitted 35.4 [9.74, 88.3] g CH_4 h^{-1} (Figure 3A, Table 1). The idle wells were sampled from Kern, Solano, Glenn, Yolo, and Sacramento counties, all areas with active oil and gas production. Four idle wells were orphaned wells (idle wells without an owner).

In California, 47% of all reported idle wells has been idle for 8 or more years (classified by CalGEM as "long-term idle") and 5% of wells has been idle for 50 or more years. The 17 idle wells that we measured had been idle on average for 13.9 years, with a range of 6−39 years. Even though our samples did not capture the wells idled for more than 50 years, our samples suggest that active and idle wells in California could be larger contributors of methane emissions than plugged wells. We also want to note again that these idle wells are considered "abandoned" in the national EPA inventories.

Unplugged. We located and sampled one unplugged well using a chamber, which was leaking at a rate of 10.9 g CH_4 h^{-1} (Figure 3A, Table 1). Unlike an idle well, this well had no production equipment on site and was not reported in the CalGEM database. We sampled this well on three separate occasions in different months (January, March, and August), with emissions varying less than 30% between each measurement (9.8, 10.1, and 12.8 g CH_4 h^{-1}, respectively), suggesting that the well's emissions varied relatively little over time. On one occasion, we measured benzene emissions at this well, which were nondetectable (detection limit 6 μg h^{-1}).

Active. We found a similar proportion of emitters in our small sample of active wells (4 of 6, or 67%) to the idle wells that we measured. The active wells that we measured were drilled between 1940 and 2005. These were measured using the MPI, which effectively captured emissions from all infrastructure present on the well pad. The mean emission from these active wells was 190 [1.03, 739] g CH_4 h^{-1} (Figure 3A, Table 1). Active wells had a mean emission 5.3 times higher than that of idle wells and a median emission 3.7 times higher. However, because of the especially small sample size of active wells, additional sampling is warranted. There is also a potential bias in these measurements; most of the sampling reported here was done at sites that were logistically feasible and accessible, typically on a public land.

Distribution of Emissions. In total, we sampled 121 abandoned, unplugged, idle, and active wells in California and found methane emissions from our set of sampled wells to vary substantially (Figure 3B, Table 1). Including values from the more sensitive static flux chamber, positive emission values were recorded over 9 orders of magnitude, ranging between 10^{-3} and 10^6 mg CH_4 h^{-1}.

Similar to most leak studies, we found that methane emissions from wells followed a "long-tail distribution", where the top few emitters are responsible for most of the emissions.[22,41] Excluding sites with methane uptake, we found that the top three positively emitting AP wells (4%) were responsible for emitting 99.6% of all emissions from AP wells. Likewise, the top two idle wells (12.5%) emitted 74.1% of all emissions from idle wells. For active wells, the single highest-emitting well (representing 16.7% of active wells sampled) emitted 96.7% of all emissions from active wells. This well was the highest emitter of any well we sampled; in fact, it had 4.5 times more emissions than the second highest emitter, an idle well. The long-tail distribution we observed is also evident by the median measurements being orders of magnitude lower than the means (Figure 3A).

Given the long-tail distribution, here we focus on the highest-emitting wells; for purposes of this analysis, we chose a "high-emitter threshold" of 1 g CH_4 h^{-1} (twice the detection limit of the MPI). If all AP wells in CA were leaking at that rate, it would be a comparable amount of methane emissions as a large dairy; instead, we found that 1 of 97 plugged wells (1%) was at this threshold. Furthermore, 7 of 17 idle wells (41%) and 4 of 6 active wells (67%) were "high-emitters". Indeed, emission factors from each well type are primarily driven by these largest emitters.

Despite our small number of sampled active and idle wells, the relative dominance of their emissions is important to note. Representatively, our average of the active wells constituted 91.1% of total well emissions measured, emitting an order of magnitude more methane than the idle wells and about 4 orders of magnitude more methane than the AP wells. Similarly, the average emission of 17 idle wells constituted 8.7% of the total measured methane emissions. We found only a small component of emissions (<1%) from plugged wells. Many more samples are necessary in large active oil and gas fields to validate these estimates.

We also measured a broad distribution of methane uptake rates (a negative emission value) from 19% of measured wells (Figure 3B), likely driven by variations in atmospheric methane being consumed by soil methanotrophs.[10] Recent work has found that methane emissions can enhance methanotrophic activity near the emission source.[14] We measured 24 AP wells and 1 idle well with negative emissions. The median uptake of these wells was 0.12 mg CH_4 h^{-1}. Given the chamber's ∼7 m^2 surface area, the average flux from these uptake areas was 0.15 g CH_4 m^{-2} $year^{-1}$. Much of the variation is likely to be natural localized variation in soil fluxes between the well measurement and the nearby control measurement. We found methane-consuming wells in nearly every geographic region that we sampled with chambers.

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δ^{13}C Isotope Signatures and Other Hydrocarbons. Along with methane emissions, we also measured the isotopic signature of methane ($\delta^{13}C-CH_4$) for 56 wells as well as ethane concentrations for 85 wells. For eight wells emitting >10 mg CH_4 h^{-1} methane where we collected both isotopic methane and ethane data, we plotted these values to determine if the emissions were of thermogenic or biogenic origin (Figure 4).[42] We found that most methane was of thermogenic origin; the one point with a higher methane/ethane ratio was leaking very little methane (60 mg h^{-1}).

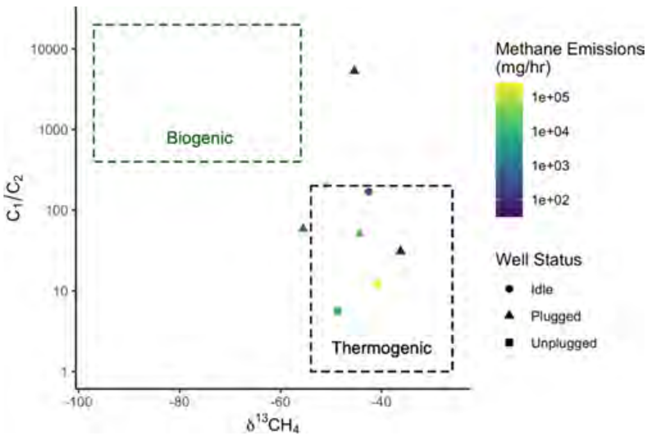

Figure 4. Bernard plot: Isotopic methane vs methane/ethane ratio. We measured eight wells which were emitting methane higher than 10 mg CH_4 h^{-1} and had collected data for both ethane and $\delta^{13}C-CH_4$. One point had a methane/ethane ratio higher than thermogenic gas; however, this well was leaking very little methane (60 mg CH_4 h^{-1}). The other samples were all classified as thermogenic, providing evidence that the measured gas comes from fossil sources and was not produced biologically through methanogenesis.

California Emissions. In 2019, California reported methane emissions of 39.9 MMT CO_2e (1.6 Tg CH_4), predominantly from agriculture (54%), landfills (21%), and oil and gas (16%).[32] Scientific research has focused on identifying major sources of methane emissions from these sectors. The 2019 California Methane Survey led by Duren et al. (2019) used the next generation airborne visible/infrared imaging spectrometer (AVIRIS-NG) to measure emissions from more than 272,000 potential sources of methane emissions in California and found a comparable distribution from the super-emitting point sources. Focusing on oil and gas, they measured 88% of the ∼225,000 oil and gas wells (all statuses) in the state. Although they had a relatively large detection limit (2−10 kg CH_4 h^{-1}), they were able to identify emissions from 107 wells; emissions from wells constituted 8.8% of total emissions from the super-emitters measured in that study.[37]

Here, we estimate the total emissions from abandoned (plugged, unplugged, and idle) wells using our emission factor and activity factors reported by CalGEM for idle and active wells. For plugged wells, we compared 57 wells selected from old USGS maps and found that 17% of wells were undocumented by CalGEM. Therefore, we estimate the activity factor for AP wells in California to be 146,000, assuming an unreported rate of 17%.

Applying these activity factors, we found that plugged wells emit 0.0004 [1×10^{-5}, 0.002] Tg CH_4 $year^{-1}$ and idle wells emit 0.0117 [0.0032, 0.0291] Tg CH_4 $year^{-1}$. Collectively, abandoned wells emit 0.012 [0.0032, 0.0311] Tg CH_4 $year^{-1}$, predominantly through idle well emissions. In total, our calculated methane emissions from abandoned wells alone represent 0.8% [0.2%, 1.9%] of California's reported emissions. Regarding the confidence intervals, it should be noted that they were calculated by directly scaling the confidence intervals from our emission factors alone by the activity factors described above. We believe that the relative error of the activity factors is much lower than the relative error of our emission factors—the EPA assumes that bounds of ±10% are reasonable when estimating the number of wells.[43]

Using a similar procedure, we found from our measurements that active wells emit 0.105 Tg CH_4 $year^{-1}$; we report this number only as a reference because of our small sample size. Nevertheless, this finding is in line with previous work on active wells specifically in California. Jeong et al. (2014) found that active wells in California emit 0.168 Tg $year^{-1}$, 0.140 Tg $year^{-1}$ from associated production and 0.028 Tg $year^{-1}$ from nonassociated production,[44] totaling 60% more emissions than we estimate from the few wells we measured. Other recent work found that active wells in Northern California emitted 7.6 kg CH_4 day^{-1},[45] comparable to our average finding of 4.6 kg CH_4 day^{-1}.

We apply our emission factors (Figure 3, Table 1) to the geographic distribution of wells in California to identify county-specific emissions, while recognizing our small sample of active wells. By applying our activity factors (Figure 1), we find that Kern County is home to the majority of wells in the California and accounts for 77% of all emissions from wells (91% of these emissions come from active wells). In addition, 6% and 4% of emissions come from wells in Los Angeles and Fresno counties, respectively.

From our measurements, our largest measurement (an active well) was emitting ∼1 kg CH_4 h^{-1}, half of the lower detection limit of AVIRIS-NG, which is used in the California Methane Survey. Based on our results, it is likely that most wells are leaking at rates too low to be detected by AVIRIS-NG; nevertheless, the largest of these emitters are leaking enough to make a substantial impact on California's methane budget. If we assume that any random sample of 121 wells of any type contains one well which leaks ∼1 kg CH_4 h^{-1}, those wells alone would contribute 0.017 Tg CH_4 $year^{-1}$ in the total methane emissions from wells, increasing the California Methane Survey's estimate of emissions from wells by 31%,[37] suggesting the importance of identifying high-emitting wells that may not be detectable by AVIRIS-NG and other airborne surveys.

Comparing Results to Other Regions. Compared to studies looking at methane emissions from abandoned oil and gas wells in other states, our results suggest that emission factors from California's wells are similar to those in other regions within the United States. For instance, in the Marcellus region of northwestern Pennsylvania, 88 wells were measured. Emission factors were found to be between 22 and 115 g CH_4 h^{-1}, with higher emitting wells generally found from gas wells than from combined oil and gas wells. These emission factors are comparable to those found from idle wells (36 g CH_4 h^{-1}) in our study. Total emissions in Pennsylvania were estimated to contribute 5−8% of the state's annual anthropogenic methane emissions from the estimated 470,000−750,000 abandoned wells in the state.[9,10] Compared to California, Pennsylvania has 4−6 times more abandoned wells and less methane emissions from other sectors, resulting in a higher fraction of emissions attributed to abandoned wells than we found in California.

In a separate work, 138 wells were measured in Wyoming, Colorado, Utah, and Ohio, where only 9 were found to be

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emitting methane, predominantly from unplugged wells.[13] Plugged wells were found to emit 0.002 g CH_4 h^{-1}, about 2 orders of magnitude less than what we found in California. Unplugged wells emitted 10.02 g CH_4 h^{-1}, similar to our findings from idle wells and unplugged wells in this study.

A different study in West Virginia found that plugged wells leaked at an average of 0.1 g CH_4 h^{-1} and unplugged wells leaked 3.2 g CH_4 h^{-1}.[11] While we did not measure enough unplugged wells to compare directly, the emission factor from the plugged wells Riddick et al.[11] sampled was a similar order of magnitude to the plugged wells in our study. This study also measured active wells and reported an average emission rate of 138 g CH_4 h^{-1}, also a similar order of magnitude to what we found in the limited number of samples in California.

Future Directions and Recommendations. The data presented here suggest that methane emissions from plugged wells in California are small compared to other well types. We found minimal evidence that AP wells were emitting substantial methane at the surface. In contrast, our small sample of idle wells (considered abandoned by the Environmental Protection Agency) suggests that idle wells contribute almost all emissions from abandoned wells. The handful of active wells that we measured suggests that emissions from these wells may be of greater concern than abandoned wells. We were unable to achieve a truly random sampling of wells across California, especially within the AP category. Most AP wells were sampled on public lands, and we could not obtain access to the large, private oil and natural gas fields in California. Additionally, the total sample of wells is small compared to the total number of wells in the state.

We recommend the following for future research on wells in California:

1. We suggest focusing additional measurements of abandoned wells on private lands, particularly those which are still unplugged and others on active oil and gas fields. A more randomized sampling approach will be able to answer questions we were unable to answer using our dataset; for example, whether or not there were correlations between emissions and well attributes. For these, we recommend a tiered-sampling approach of a truly randomized sample, where the highest emitters are rapidly identified, followed by more precise sampling using one of the methods discussed here or a new method.

2. We recommend further investigation on the contribution of idle and active wells to overall emissions. Additional samples of idle and active wells should be collected with a lower detection limit sufficient to capture the high emitters missed by Duren et al. in the California Methane Survey (the detection limit was 2 kg h^{-1}).[37] This work is in line with the proposed legislation in California, particularly Assembly Bill 1328. For idle wells, we recommend finding and sampling some of the 1626 idle wells that have been idle for 50 years or more. Ideally, additional measurements for any well type would utilize new technology, such as drones, to be able to efficiently locate (in the case of buried wells) and quickly measure methane emissions from the wells. Drone technology is now capable of both. If 1% of plugged, idle, and active wells leaked at a rate of 1 kg CH_4 h^{-1} (below the detection limit of AVIRIS-NG), that would account for an additional ~30% more emissions from wells than was found by Duren et al.[37] To adequately test this possibility, we recommend testing ~1000 randomly selected wells at a detection limit of ~10 g CH_4 h^{-1}. We recommend this detection limit because the current drone technology can achieve this sensitivity, and we encourage the use of drones for rapid sampling.

3. We recommend additional measurements in zones of subsidence, particularly in the regions in the San Joaquin Valley where high levels of subsidence due to groundwater pumping have been observed. This will likely require hundreds of additional measurements to draw strong conclusions regarding whether subsidence affects methane emissions from oil and gas wells. With enough samples and access to data, effects of well age, plugging date, drill depth, and seismic activity on emissions could also be investigated.

4. We report only on methane emissions to the atmosphere in this study, but there is additional concern that wells leak methane below the ground, which could contaminate groundwater. Especially for wells abandoned prior to 1974 when stricter abandonment regulations were enacted, we recommend a separate campaign to investigate groundwater contamination from subsurface well leakage arising from improper/failed well abandonment.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.0c05279.

Additional details about the methodology, including the geomagnetic surveys, chambers, mobile plume integrator; analyzers used; and description of the tar pit in Los Angeles County (PDF)

Spreadsheet containing specific emissions measurements for individual wells measured in this study (XLSX)

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Notes

The authors declare no competing financial interest.

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October 1, 2021

RE: Response to CalGEM Questions for the California Oil and Gas Public Health Rulemaking Scientific Advisory Panel

Director Shabazian and Supervisor Ntuk,

Please find attached the responses from the California Oil and Gas Public Health Rulemaking Scientific Advisory Panel to the written questions sent by the California Geologic Energy Management Division (CalGEM) on August 31, 2021.

We would be glad to answer any further questions that may arise.

Best Regards,

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CalGEM Questions for the California Oil and Gas Public Health Rulemaking Scientific Advisory Panel

CalGEM requests the California Oil and Gas Public Health Rulemaking Scientific Advisory Panel assistance with the following questions:

1. ***How would the panel characterize the level of certainty that proximity to oil and gas extraction wells and associated facilities in California causes negative health outcomes? Is there a demonstrated causal link between living near oil and gas wells and associated facilities and health outcomes?***

We have focused our review on epidemiological studies carried out in multiple oil and gas regions, including Colorado, which has a similar regulatory context as California. Given that similar environmental health hazards and risks are intrinsic to both conventional and unconventional oil and gas development (OGD), including exposure pathways, chemicals associated with hydrocarbon reservoirs, use of ancillary equipment, and non-chemical stressors (See section on "Similarities and Differences Between Unconventional and Conventional OGD"), the California Oil and Gas Public Health Rulemaking Scientific Advisory Panel (Panel) concludes that the full body of epidemiologic literature is relevant to assess the human health hazards, risks and impacts of upstream OGD in California.

Our Panel concludes with a high level of certainty[1] that the epidemiologic evidence indicates that close residential proximity to OGD is associated with adverse perinatal and respiratory outcomes, for which the body of human health studies is most extensive in California and other locations.

Studies on Oil and Gas Development and Perinatal Outcomes

Perinatal outcome studies provide the largest [19 studies][2] and strongest body of evidence linking OGD exposure during the sensitive prenatal period with adverse health effects. The majority of studies that examine perinatal effects found increased risk of adverse birth outcomes in those most exposed to OGD (measured using metrics including, but not limited to proximity, well density, and production volume). It should also be noted that adverse perinatal outcomes, including preterm births, low birth weight, and small-for-gestational age births

[1] In this document, the statement, "a high-level of certainty" is based on the professional judgement of all California Oil and Gas Public Health Rulemaking Scientific Advisory Panel (Panel) members in their assessment of the scientific evidence. In terms of panel process, all Panel members agree with the responses to the questions in this document. Any Panel member could have written a dissenting opinion, but no one requested to do so. This document reflects the perspective of the Panel members and not necessarily the opinions of their employers or institutions.

[2] Apergis et al., 2019; Busby & Mangano, 2017; Caron-Beaudoin et al., 2020; Casey et al., 2016; Currie et al., 2017; Cushing et al., 2020; Gonzalez et al., 2020; Hill, 2018; Janitz et al., 2019; Ma, 2016; McKenzie et al., 2014, 2019; Stacy et al., 2015; Tang et al., 2021; Tran et al., 2020, *Forthcoming*; Walker Whitworth et al., 2018; Whitworth et al., 2017; Willis et al., 2021.

increase the risk of mortality and long-term developmental problems in newborns (Liu et al., 2012; Vogel et al., 2018) as well as longer term morbidity through adulthood (Baer et al., 2016; Barker, 1995; Carmody & Charlton, 2013; Frey & Klebanoff, 2016).

Perinatal Outcomes Associated with Conventional and Unconventional Oil and Gas Development

While many perinatal outcome studies outside of California focus on unconventional OGD (e.g., high-volume hydraulic fracturing), a recent review of the literature (Deziel et al., 2020), highlighted the need for an updated assessment of the health effects associated with OGD more generally, as both conventional and unconventional OGD operations present health risks, especially to those living in close proximity. This bolsters conclusions reached by the authors of the 2015 independent scientific study of hydraulic fracturing and well stimulation in California led by the California Council on Science and Technology (CCST) (Long et al., 2015) pursuant to Senate Bill 4 (2013, Pavley). Recent studies in California have reported associations between exposure to OGD and adverse birth outcomes, considering wells under production using enhanced oil recovery including cyclic steam injection, steam flooding and water flooding -- methods that do not meet the definition of unconventional development (Gonzalez et al., 2020; Tran et al., 2020, *Forthcoming*). Similar findings regarding adverse birth outcomes have been reported while examining unconventional OGD in Colorado, Oklahoma, Pennsylvania and Texas (Apergis et al., 2019; Casey et al., 2016; Cushing et al., 2020; Gonzalez et al., 2020; Hill, 2018; McKenzie et al., 2019; Stacy et al., 2015; Walker Whitworth et al., 2018; Whitworth et al., 2017). In the California independent scientific study on well stimulation pursuant to Senate Bill 4 (2013, Pavley), the authors concluded that while hydraulic fracturing introduces some specific human health risks, the majority of environmental risks and stressors are similar across conventional and unconventional oil and gas operations (Long et al., 2015; Shonkoff et al., 2015). Further, a handful of epidemiological studies explicitly examine potential differences in associations between conventional or unconventional oil or natural gas development and adverse outcomes. For example, Apergis et al. (2019) reported statistically significant reductions in infant health index within 1 km of both conventional and unconventional drilling sites in Oklahoma. <u>In summary, the Panel concludes with a high level of certainty that human health studies focused on unconventional and conventional OGD are relevant to consider in the California context where conventional development is most prevalent.</u>

Consistency Across Perinatal Epidemiology Studies

<u>We have a high level of certainty in the findings in the body of epidemiological studies for perinatal health outcomes because of the consistency of results across multiple studies that were conducted using different methodologies, in different locations, with diverse populations, and during different time periods</u> (see **Table 1** below). Most of these studies entail rigorous, high quality analyses (i.e., study designs that establish temporality based on large sample sizes, control for potential individual and area-level confounders, apply rigorous statistical

modelling techniques, and conduct sensitivity analyses to assess the robustness of effects). A variety of pollutants (e.g., $PM_{2.5}$ and air toxics) and other OGD stressors are associated with these same adverse birth outcomes (Dzhambov & Lercher, 2019; Nieuwenhuijsen et al., 2017; Shapiro et al., 2013), which further strengthens the evidence of the link between OGD and adverse perinatal outcomes. Therefore, the totality of the epidemiological evidence provides a high level of certainty that exposure to OGD (and associated exposures) cause a significant increased risk of poor birth outcomes.

Further, imprecision in exposure assessment or non-differential exposure misclassification in some of the epidemiological studies is more likely to attenuate observed relationships, thus leading to an underestimate of the true adverse impacts of OGD on birth outcomes (**Figure 1**). In environmental epidemiologic studies, researchers often use surrogates to estimate exposures or assign individuals to exposure categories; these surrogates have some measurement error associated with them. When these errors in assigning or classifying participant exposures are similar between exposed and unexposed or those with or without the health outcome, this is referred to as non-differential exposure misclassification. This type of "noise" in the data tends to dilute or attenuate the true exposure-response relationship, as illustrated by the hypothetical dashed line in **Figure 1**, which has a shallower slope compared to the hypothetical "true" solid line.

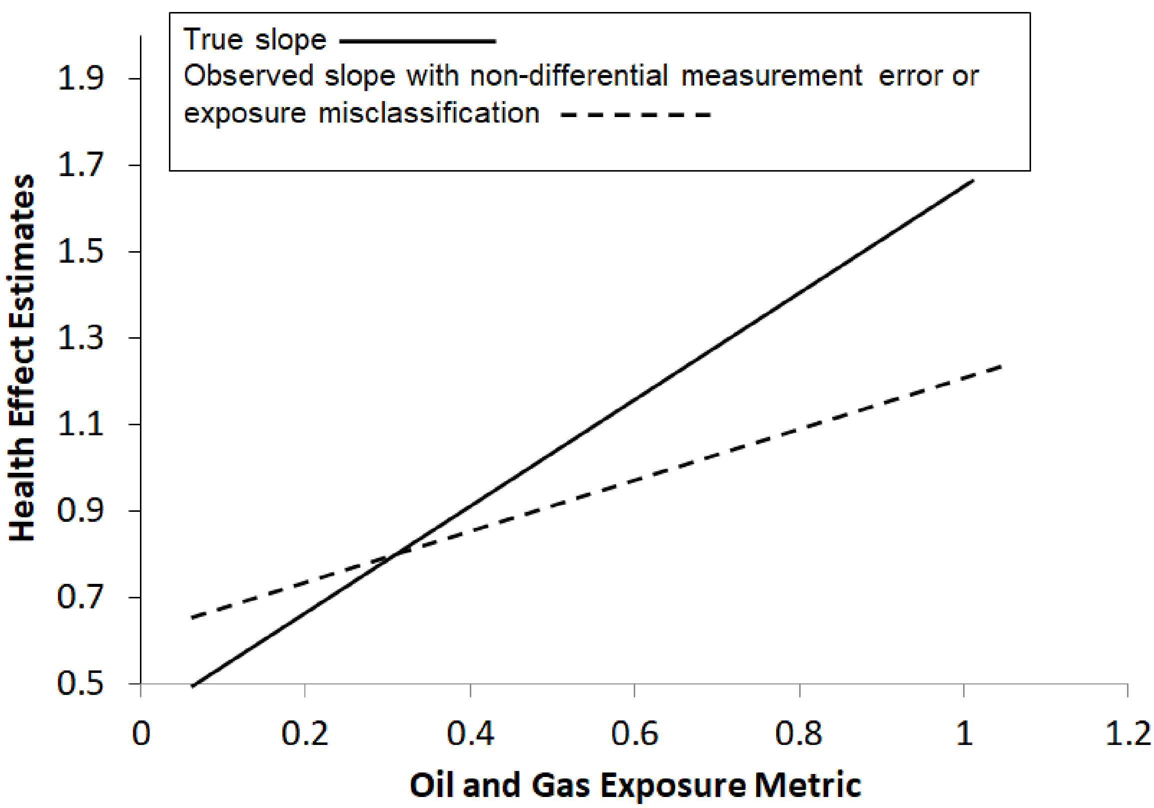

Figure 1. Effect of imprecise exposure estimates on a hypothetical exposure-response relationship (Source: Adapted from Seixas & Checkoway, 1995).

Respiratory Risks and Impacts from Oil and Gas Development

Respiratory health outcomes are the second most studied health outcomes in the epidemiological literature examining OGD, with eight peer-reviewed studies published to date. Two peer-reviewed studies in California found an association between OGD and self-reported and physician-diagnosed asthma, reduced lung function, and self-reported acute respiratory symptoms (e.g., recent wheeze) (Johnston et al., 2021; Shamasunder et al., 2018). Six studies in other oil and gas regions (Pennsylvania and Texas) reported an association between OGD and asthma exacerbations, asthma hospitalizations, and respiratory symptoms (Koehler et al., 2018; Peng et al., 2018; Rabinowitz et al., 2015; Rasmussen et al., 2016; Willis et al., 2018, 2020).

Epidemiological studies, by design, often use aggregate measures of exposure to account for multiple potential stressors and pathways associated with OGD (e.g., air pollution, noise pollution, groundwater and/or drinking water contamination). Many criteria air pollutants (e.g., particulate matter, ozone, nitrogen oxides) and hazardous air pollutants emitted from OGD have a well-established body of scientific literature indicating that exposure to these pollutants causes an increased risk of development and exacerbation of respiratory disease (Bolden et al., 2015; Ferrero et al., 2014). We reiterate the relevance of studies on both conventional and unconventional OGD for respiratory health outcomes. For example, (Willis et al., 2020) found that both conventional and unconventional natural gas development at the ZIP code level was associated with pediatric asthma hospitalizations in Texas.

Comparing The Body of Perinatal and Respiratory Outcome Studies Against The Bradford Hill Criteria for Causation

Below, we demonstrate how the body of epidemiological studies on the relationship between OGD and perinatal and respiratory outcomes meets the nine Bradford Hill Criteria for Causation (Hill, 1965; Lucas & McMichael, 2005). The Bradford Hill Criteria are used to evaluate the strength of epidemiological evidence for determining a causal relationship between an exposure and observed effect. These criteria are widely used in the field of epidemiology and public health practice to guide decision-making. After considering these criteria, the Panel concludes with a high level of certainty that there is a causal relationship between close geographic proximity to OGD and adverse perinatal and respiratory outcomes (**Table 1**).

Table 1. Application of the Bradford Hill Criteria for Causation to the peer-reviewed epidemiological literature on oil and gas development and perinatal and respiratory health outcomes.

Criteria for Causation (Bradford-Hill)	Description of Criteria	Perinatal Health Studies	Respiratory Health Studies
Strength of Association	Environmental studies commonly report modest effects sizes (i.e., relative to active tobacco smoking or alcohol consumption). A small magnitude of association can support a causal relationship, a larger association may be more convincing.	Reported effect sizes are in ranges similar to other well-established environmental reproductive and developmental hazards, such as $PM_{2.5}$ (Dadvand et al., 2013; C. Li et al., 2020). Some studies, particularly those in California, have found stronger effect estimates for OGD exposures among socially marginalized groups (Cushing et al., 2020; Gonzalez et al., 2020; Tran et al., 2020, *Forthcoming*).	Reported effect sizes are in ranges similar to other well-established environmental respiratory hazards. For example, effect sizes in reductions in lung function by Johnston et al. (2021) are similar in magnitude to reductions in lung function associated with secondhand smoke exposure among women (Eisner, 2002) and reductions in lung function among adults living near busy roadways (e.g., (Kan et al., 2007).
Consistency	Consistent findings observed by different persons in different places with different samples strengthens the likelihood of an effect.	Adverse birth outcomes have been observed in multiple studies using multiple methods in different populations at different times and locations (e.g., California, Pennsylvania, Colorado, Texas). While there is some variation in findings by specific perinatal outcomes, the overall body of evidence is highly consistent in supporting the association between OGD and adverse perinatal outcomes.	Various respiratory health outcomes are evaluated in the literature. For asthma -- the most commonly studied respiratory health outcome -- studies across California, Pennsylvania and Texas consistently show an association between OGD and asthma-related metrics (asthma prevalence, exacerbations, pediatric hospitalizations) (Koehler et al., 2018; Rasmussen et al., 2016; Shamasunder et al., 2018; Willis et al., 2018, 2020) .

Criteria for Causation (Bradford-Hill)	Description of Criteria	Perinatal Health Studies	Respiratory Health Studies
Specificity	Causation is likely if there is no other likely explanation.	All peer-reviewed birth outcome studies included in our review controlled for other potential confounders by (i) accounting or adjusting for other individual-level or area-level factors (e.g., other air pollution sources, neighborhood socioeconomic status) in the analysis (Casey et al., 2016; McKenzie et al., 2014; Tran et al., 2020, *Forthcoming*). Other studies applied statistical modeling approaches such as difference-in-difference that accounts for temporal and spatial trends that may confound observed effects (Willis et al., 2021).	Most respiratory health studies have controlled for other potential explanatory or confounding factors by (i) accounting or adjusting for other individual-level (e.g., smoking status) or area-level factors (e.g., other air pollution sources) in the analysis (Johnston et al., 2021; Koehler et al., 2018; Peng et al., 2018; Rabinowitz et al., 2015; Rasmussen et al., 2016; Willis et al., 2018, 2020), or in the study design, such as utilizing a difference-in-difference methodology (Peng et al., 2018; Willis et al., 2018).
Temporality	Exposure precedes the disease.	Most birth outcomes studies have proper temporal alignment between exposure and outcome and use a retrospective cohort, case control or other study design that allows retroactive assessment of exposures to OGD occurring before the onset of disease. They do not consider exposure that occurred at the time of disease or oil and gas wells drilled after the disease.	Some respiratory health studies do not allow for assessments of exposure that predate disease. However, of the studies with the proper temporal alignment (Johnston et al., 2021; Koehler et al., 2018; Peng et al., 2018; Rasmussen et al., 2016; Willis et al., 2018), authors report statistically significant associations between OGD and oral corticosteroid medication orders, asthma hospitalizations and asthma-related emergency department visits.

Criteria for Causation (Bradford-Hill)	**Description of Criteria**	**Perinatal Health Studies**	**Respiratory Health Studies**
Biological Gradient (Dose-Response)	Greater exposure leads to a greater likelihood of the outcome.	Some studies have found dose-response relationships based on oil and gas production volume categories or metrics of inverse distance weighting and/or oil and gas well density in California and elsewhere (Casey et al., 2016; McKenzie et al., 2014, 2019; Tang et al., 2021; Tran et al., 2020).	Larger reductions in lung function observed with decreased distance from active oil development sites (Johnston et al., 2021).
Plausibility	The exposure pathway and biological mechanism is plausible based on other knowledge.	Individual health-damaging chemical pollutants are well-understood to be emitted from OGD (e.g., $PM_{2.5}$, benzene) and established as contributing to increased risk for the same adverse perinatal outcomes observed in the epidemiology studies. Stressors associated with OGD (e.g., psychosocial stress; (Casey et al., 2019) can also contribute to increased adverse perinatal outcomes.	Many air pollutants associated with OGD are well-known to contribute to respiratory morbidity and mortality, including exacerbations of existing respiratory conditions (Guarnieri & Balmes, 2014).
Coherence	Causal inference is possible only if the literature or substantive knowledge supports this conclusion.	In particular, the body of peer-reviewed literature is converging towards singular directions for adverse perinatal outcomes.	The body of peer-reviewed literature points in a singular direction for adverse respiratory health outcomes.

Criteria for Causation (Bradford-Hill)	Description of Criteria	Perinatal Health Studies	Respiratory Health Studies
Experiment	Causation is a valid conclusion if researchers have seen observed associations in prior experimental studies.	N/A- Human population-based experimental studies are not available due to ethical issues.	N/A- Human population-based experimental studies are not available due to ethical issues.
Analogy	For similar programs operating, similar results can be expected to bolster the causal inference concluded.	Pollutants well known to be emitted during OGD including benzene, toluene and 1,3 butadiene are listed as reproductive or developmental toxicants under Prop 65 and thus are recognized as such by the State of California (CalEPA OEHHA, 2021). EPA's current Integrated Science Assessments of particulate matter and tropospheric ozone conclude that the evidence is suggestive of, but is not sufficient to infer, a causative relationship between birth outcomes, including preterm birth and low birth weight, and $PM_{2.5}$ and long term ozone exposures (US EPA, 2019, 2020). Additionally, increased stress during pregnancy can alter fetal growth and length of gestation (Fink et al., 2012).	EPA's current Integrated Science Assessments of particulate matter and tropospheric ozone conclude that there is: a casual relationship between respiratory outcomes, including asthma and short term ozone exposure; and likely a causal relationship between respiratory outcomes, including asthma and: short and long term $PM_{2.5}$ exposure; and long term ozone exposure (US EPA, 2019, 2020).

Similarities and Differences Between Unconventional and Conventional Oil and Gas Development

Though definitions of conventional and unconventional OGD may differ across different regulatory and policy landscapes, the majority of OGD in California is often considered conventional, involving vertical drilling at shallower depths into target geologies that hold migrated hydrocarbons. These attributes of development are often considered in contrast to unconventional OGD, which can involve horizontal directional drilling in deeper wells to access source rock formations by increasing the permeability of these tight formations using mostly hydraulic fracturing. In addition, these unconventional operations are often accompanied with greater masses of material inputs (e.g., water, chemical additives, proppants) and a greater magnitude of liquid and solid waste outputs (e.g., flowback fluids and produced water). It should be noted, however, that hydraulic fracturing that takes place in California often uses fluids (gels) with higher concentrations of well stimulation chemicals than those fluids used in high-volume slick water hydraulic fracturing of source rock in other parts of the United States (Long et al., 2015).

However, many environmental and health hazards and risks are intrinsic to both conventional and unconventional OGD (Hill et al., 2019; Jackson et al., 2014; Lauer et al., 2018; Stringfellow et al., 2017; Zammerilli et al., 2014). $PM_{2.5}$ and nitrogen oxides emissions result from the use of diesel-powered equipment and trucks and hazardous air pollutants such as benzene, toluene, ethylbenzene and xylene (BTEX) occur naturally in oil and gas formations, regardless of the type of extraction method employed. Noise pollution, odors, and landscape disruption are inherent to OGD. Investigations in other oil and gas states have noted radioactivity on particles downwind from unconventional oil and gas wells (Li et al., 2020b) and in sediment downstream of water treatment plants that treat waste from conventional as well as unconventional oil and gas operations (Burgos et al., 2017; Lauer et al., 2018).

In California, policy, regulatory and scientific emphasis has been placed on well stimulation activities, including hydraulic fracturing, matrix acidizing and acid fracturing. The 2015 Independent Scientific Assessment on Well Stimulation in California, which focused primarily on well stimulation activities pursuant to Senate Bill 4 (2013, Pavley), reported the following key conclusion: *"The majority of impacts associated with hydraulic fracturing are caused by the indirect impacts of oil and gas production enabled by the hydraulic fracturing"* (Long et al., 2015). Indirect impacts relevant to human health for the purposes of the study included: "proximity to any oil production, including stimulation- enabled production, could result in hazardous emissions to air and water, and noise and light pollution that could affect public health" (Long et al., 2015). Additionally, a recent evaluation of chemical usage during OGD in California found significant overlap in chemical additives used for well stimulation (including hydraulic fracturing) and those used in routine activities, such as well maintenance (Stringfellow et al., 2017).

2. What are the air pollutants released from these activities that cause negative health outcomes? How do we know exposure to these is likely from oil and gas extraction wells and associated facilities, as opposed to other sources?

The wells, valves, tanks and other equipment used to produce, store, process and transport petroleum products at both unconventional and conventional OGD sites are associated with emissions of toxic air contaminants, hazardous air pollutants and other health-damaging non-methane VOCs (Helmig, 2020; Moore et al., 2014). Diesel engines used to power on-site equipment and trucks at unconventional and conventional OGD sites directly emit health-damaging hazardous air pollutants, fine particulate matter ($PM_{2.5}$), nitrogen oxides and volatile organic compounds (VOCs) (CalEPA OEHHA, 2001). Many VOCs and nitrogen oxides are precursors to ground level ozone (O_3) formation, another known health harming pollutant. Hazardous air pollutants that are known to be emitted from OGD sites include benzene, toluene, ethylbenzene, xylenes, hexane and formaldehyde--many of which are known, probable or possible carcinogens and/or teratogens and which have other adverse effects for non-cancer health outcomes (CalEPA OEHHA, 2008, 2009; Moore et al., 2014). In the San Joaquin Valley Air Pollution Control District, OGD activities are responsible for the majority of emissions of multiple toxic air contaminants including acetaldehyde, benzene, formaldehyde, hexane and hydrogen sulfide (**Figure 2**) (Brandt et al., 2015; Long et al., 2015).

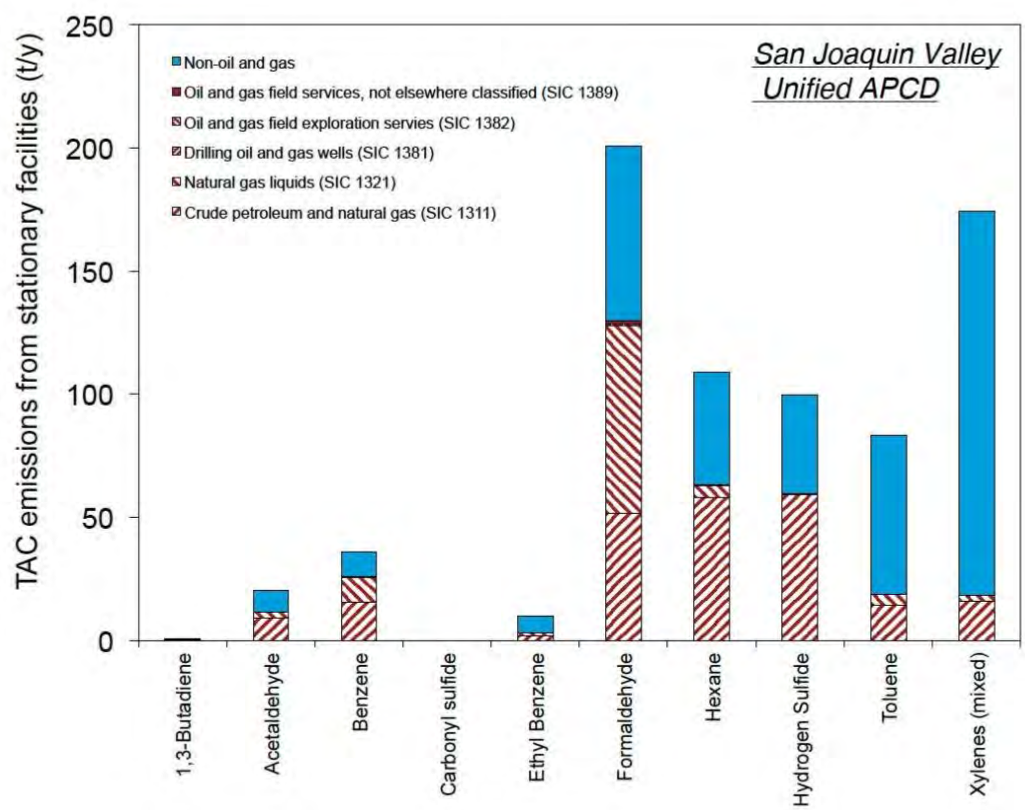

Figure 2. **Toxic Air Contaminant emissions from stationary facilities in the San Joaquin Valley Air Pollution Control District (Source: (Brandt et al., 2015).**

A recently published study using statewide air quality monitoring data from California investigated whether drilling new wells or increasing production volume at active wells resulted in emissions of $PM_{2.5}$, nitrogen dioxide (NO_2), VOCs, or O_3 (Gonzalez et al., 2021)**.** To assess the effect of oil and gas activities on concentrations of air pollutants, the authors used daily variation in wind direction as an instrumental variable and used fixed effects regression to control temporal factors and time-invariant geographic factors. The authors documented higher concentrations of $PM_{2.5}$, NO_2, VOCs, and O_3 at air quality monitoring sites within 4 km of pre-production OGD well sites (i.e., wells that were between spudding and completion) and 2 km of production OGD well sites, after adjusting for geographic, meteorological, seasonal, and time trending factors. In placebo tests, the authors assessed exposure to well sites downwind of the air monitors and observed no effect on air pollutant concentrations. **Table 2** summarizes the increases in each pollutant for each additional upwind well site by distance.

Table 2. Summary of air pollutant concentrations measured between 2006-2019 at 314 air quality monitoring sites in the EPA Air Quality System for California (Gonzalez et al., 2021*).*

Distance	$PM_{2.5}$ µg/m^3*	NO_2 ppb	VOCs (ppb C)*	O_3 (ppb)
Estimated increase for each additional upwind pre-production well site				
Within 2 km	2.35 (0.81, 3.89)	2.91 (0.99, 4.84)	No increase	no increase
2-3 km	0.97 (0.52, 1.41)	0.65 (0.31, 0.99)	No increase	0.31 (0.2, 42)
3-4 km	no increase	no increase	no increase	0.14 (0.05, 0.23)
Estimated Increase for each 100 BOE of total oil and gas upwind production volume				
1 km	1.93 (1.08, 2.78)	0.62 (0.37, 0.86)	0.04 (0.01, 07)	no increase
1-2 km	no increase	no increase	no increase	0.11 (0.08, 0.14)

*No $PM_{2.5}$ or VOC monitoring sites with 1 km of pre-production well sites; BOE, barrels of oil equivalents.

These multiple stressors, along with other physical factors such as noise and vibration, are consistently found in exposure studies to be measurably higher near oil and gas extraction wells and other ancillary infrastructure in California. As such, the Panel concludes with a high level of certainty that concentrations of health-damaging air pollutants, including criteria air pollutants and toxic air contaminants, are more concentrated near OGD activities compared to further away.

3. ***Does the evidence evaluated clearly support a specific setback? If so, what is this setback distance and what oil and gas extraction activities would it specifically apply to? What is the supporting evidence?***
    a. ***How does this evidence justify the recommended setback distance, as opposed to another distance?***

Existing epidemiologic studies were not designed to test and establish a specific "safe" buffer distance between OGD sites and sensitive receptors, such as homes and schools. Nevertheless, studies consistently demonstrate evidence of harm at distances less than 1 km, and some studies also show evidence of harm linked to OGD activity at distances greater than 1 km. In addition, exposure pathway studies have demonstrated through measurements and modelling techniques, the potential for human exposure to numerous environmental stressors (e.g., air pollutants, water contaminants, noise) at distances less than 1 km (e.g., Allshouse et al., 2019; Holder et al., 2019; McKenzie et al., 2018; DiGiulio et al., 2021; Soriano et al., 2020), and that the likelihood and magnitude of exposure decreases with increasing distance.

b. ***What are the health benefits from this setback? Can the panel quantify them or recommend a methodology CalGEM can use to quantify them? Can the panel establish that these health benefits can only be achieved with the setback? Or can they also be achieved with mitigation controls?***

Figure 3 presents a hierarchy of strategies to reduce human health hazards, risks and impacts from OGD activities. **Table 3** presents the advantages and disadvantages of each strategy from an environmental public health perspective.

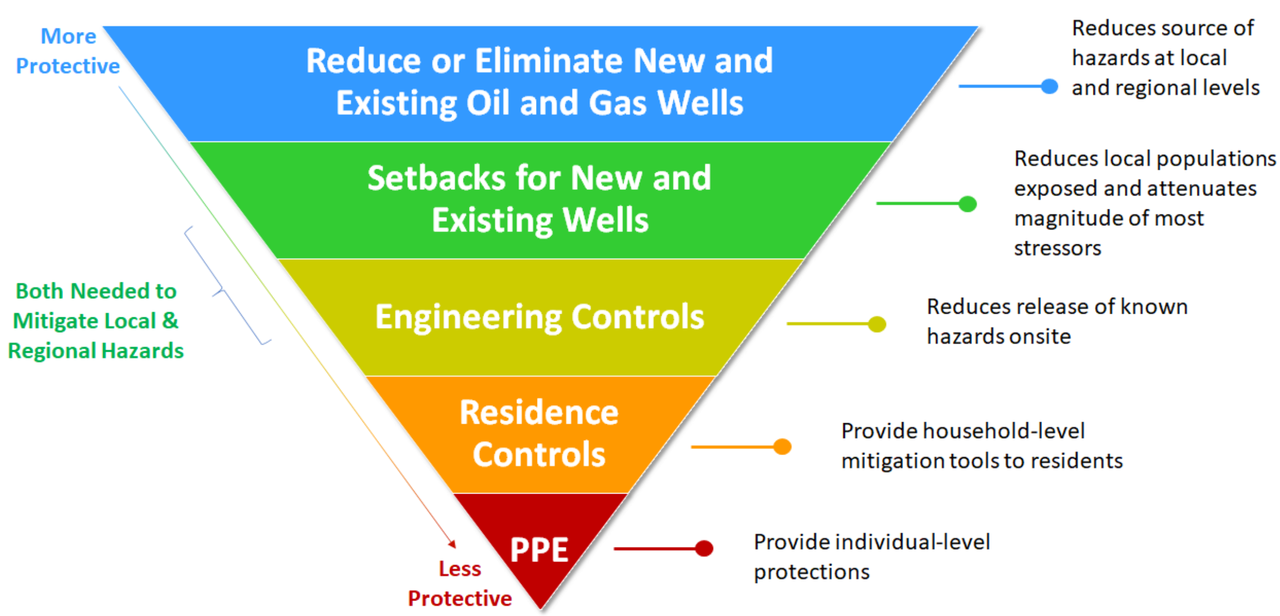

Figure 3. Hierarchy of strategies to reduce or eliminate public health harms for OGD activities. Note: the use of the term "wells" includes the ancillary infrastructure used to develop, gather and process oil and gas in the upstream oil and gas sector.

At the top of Figure 3 is the most health protective strategy: to stop drilling and developing new wells, phase out existing OGD activities and associated infrastructure, and properly plug remediate legacy wells and ancillary infrastructure.

If the development of oil and gas is to continue, the greatest health benefits would be gained from a strategy that includes the next two controls in the hierarchy depicted in Figure 3: the elimination of new and existing wells and ancillary infrastructure within scientifically informed setback distances and the deployment of engineering emission controls and associated monitoring approaches that lead to rapid leak detection and repair for new and existing wells and ancillary infrastructure. Because air pollutant concentrations and noise levels decrease with increasing distance from a source, adequate setbacks can reduce harm to local populations by reducing exposures to air pollutants and noise directly emitted from the OGD activities. However, setbacks do not reduce harms from OGD contributions to regional air pollutant levels, such as secondary particulate matter and ozone, or greenhouse gases, such as methane, which are nearly always co-mingled with health-damaging air pollutants (Michanowicz et al., *Forthcoming*). Engineering controls that reduce emissions at the well site are also necessary to reduce these harms.

Engineering controls include cradle-to-grave noise and air pollution emission mitigation controls on OGD infrastructure including new, modified and existing infrastructure, and proper abandonment of legacy infrastructure, prioritizing those nearest to residential sites and schools and those associated with the highest emissions, leaks and other environmental hazards.

However, engineering controls can fail and engineering solutions may not be available for or economically feasible to handle all of the complex stressors generated by OGD, including multiple sources and types of air pollution, noise pollution, light pollution, water pollution, and other stressors. Therefore, neither setbacks or engineering controls alone are sufficient to reduce the health hazards and risks from OGD activities -- both approaches are needed in tandem.

Finally, we note that while outside of CalGEM's jurisdiction, setbacks for new construction of housing or schools at a certain distance from existing or permitted OGD sites (commonly referred to as reverse setbacks), should be considered.

Table 3. Advantages and Disadvantages of Oil and Gas Development Control Strategies from an Environmental Public Health Perspective.

Control Strategy	Description	Advantage	Disadvantage
Elimination	Eliminate or reduce new and existing wells and ancillary infrastructure in combination with proper plugging and abandonment of wells and other legacy infrastructure.	Eliminates the source of nearly all environmental stressors (e.g., air and water pollutants, noise); protects local and regional populations	None.
Setbacks	Increase the distance between OGD hazards and sensitive receptors.	Reduces risk of exposures to populations living near OGD sites; environmental stressors are generally attenuated with increasing distance.	Setbacks alone without coupled engineered mitigation controls allow continued release of hazards and therefore does not adequately address air pollutant and greenhouse gas emissions from OGD and their impacts on regional air quality and the climate.
Engineering Controls	Reduces or eliminates release of specific hazards on site.	Reduces or eliminates certain hazards and therefore can have local and regional environmental public health benefits.	Tends to be disproportionately focused on air pollutant emissions. Often not feasible to apply engineering solutions to multiple, complex stressors each requiring different control technologies (e.g. noise, air and water impacts, social stressors) and lacks the important factor of safety provided by a setback when engineering controls fail.
Residence Controls	Provides households with devices to reduce hazard at the home (e.g., water filter, light-blocking shades, air filters).	Reduces intensity of certain hazards to nearby communities at the household level.	Places burden on individuals and households to use devices properly and to maintain and regularly replace controls to maximize effectiveness. Not feasible to apply devices to address numerous, complex stressors.
Personal Protective Equipment	Provide individuals with devices to reduce exposure (e.g., respiratory masks, ear plugs, eye masks).	Reduces intensity of exposure of certain hazards to nearby individuals.	Places burden on individuals to use PPE consistently and properly and is not feasible for the complex stressors.

Attributable Risk Calculations

One method to estimate health harms from OGD is to use the measures of association from the epidemiologic literature and population counts to calculate the excess number of specific health outcomes. This is what is known as an attributable risk method. We may be able to derive these estimates in the final report for birth outcomes using estimates of population counts for women of reproductive age in California living near OGD sites. We will also attempt to derive similar estimates for respiratory outcomes by using age appropriate population counts near OGD sites. This attributable risk method can allow us to estimate the number of adverse perinatal or respiratory cases that are attributable to OGD exposures and could be attenuated through the implementation of elimination or setback strategies.

c. ***Can the panel quantify or recommend a methodology CalGEM can use to quantify the health benefits associated with mitigation controls?***

The Panel was not tasked to estimate health benefits of various setbacks and mitigation strategies, which pose significant methodological challenges and would require considerable time and effort. Among the challenges is the need to consider the benefits of reducing multiple stressors -- multiple air pollutants and other chemicals, noise, vibration, light, subsurface contamination, etc.

Known Health Benefits of Reducing Air and Noise Pollution

There is a significant body of literature and available tools that address the potential health benefits that can be achieved by reducing air and noise pollution exposures. The National Institute of Environmental Health Sciences has linked air pollution and specifically $PM_{2.5}$ to respiratory disease, cardiovascular disease, cancer, and reproduction harm and provides references supporting these links (NIEHS (National Institute of Environmental Health Sciences), 2021). Schraufnagel et al. (2019) examined in detail the health benefits of air pollution reductions in different geographic regions. Friedman et al. (2001) showed that improvements in air quality in preparation for the 1996 Atlanta Olympics resulted in significantly lower rates of childhood asthma events, including reduced emergency department visits and hospitalizations. Avol et al. (2001) demonstrated that children in southern California who moved to communities with higher air pollution levels had lower lung function growth rates than children who moved to areas with lower air pollution levels. Gauderman et al. (2015), examining the impact of reductions in $PM_{2.5}$ and nitrogen dioxide in the Los Angeles air basin, found that children who grew up after air quality improvements had less than ½ the chance of having clinically low lung function results. Ha et al. (2014) found $PM_{2.5}$ exposures in all trimesters to be significantly and positively associated with the risk of all adverse birth outcomes.

In an analysis of noise exposure reductions. Based on sound levels measured and/or modeled across the US together with an EPA exposure- response model for levels exceeding EPA standards, Swinburn et al. (2015) found that a 5-dB noise reduction scenario in communities with noise exceeding EPA standards would reduce the prevalence of hypertension by 1.4% and coronary heart disease by 1.8%. The types of health-benefit studies noted here provide a basis for conducting a health-benefits analysis using a tool such as US EPA's Environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) (US EPA, 2021).

Possible Approaches to Quantify Health Benefits

CalGEM could obtain estimates of the health benefits achieved from different mitigation strategies individually or in combination with tools such as the Community Multiscale Air Quality Model (CMAQ) (Binkowski & Roselle, 2003) and/or other exposure assessment tools and link model output to EPA's BenMAP-CE (US EPA, 2021). However, these models and approaches are only focused on air quality and noise. It should also be noted that a significant drawback of using BenMAP-CE for this application is that it only considers impacts from criteria air pollutants and not from toxic air contaminants or other emerging air pollutants.

BenMAP-CE estimates the number and economic value of health impacts resulting from changes in air pollution concentrations. BenMAP-CE estimates benefits in terms of the reductions in the risk of premature death, heart attacks, and other adverse health effects. BenMAP-CE requires as input, pollutant concentrations at a scale that matches with population data. These concentrations can be obtained from a model such as CMAQ (Binkowski & Roselle, 2003) or from a monitoring network. BenMAP-CE takes the concentration fields for a base case and then for a pollution reduction (or increase) to assess health benefits (or detriments). BenMAP-CE then estimates changes in health endpoints, allowing the user to specify the concentration–response function and either use built-in population and baseline mortality rates or specify them as inputs.

It should be noted that in order to use a model such as BenMAP-CE to assess health benefits of setbacks and mitigation controls at well sites across California would involve a significant level of time and effort in data collection and model executions. In addition, these models are limited to characterizing the health benefits of criteria air pollutant reductions, but do not account for other OGD related exposures such as toxic air contaminants, other chemical exposures and exposures to other stressors through other environmental pathways (e.g., water and noise). Additionally, and importantly, the lack of spatially resolved emissions data from upstream OGD introduces challenges when assessing local- and sub-regional scaled health impacts that would be required for calculating benefits of specific policies such as setbacks and emission control. As such, attempts to quantify benefits using BenMAP-CE are likely to underestimate them.

4. ***CalGEM is aware of health risk assessments, health impact assessments, air exposure studies, and workforce safety studies that have been conducted but were not evaluated as part of your preliminary advice. How do these studies align with your causation determination, any recommended setback distance, and recommendations on health benefits quantification?***

The Panel determined early in its deliberations that it would limit the studies assessed in its report to those in the peer-reviewed scientific literature. This criterion ensures that studies have been evaluated by scientists who have not been involved with the study but have expertise in the relevant topic area and/or the methods used to carry out analyses, prior to publication. The peer-review process helps to ensure that high quality data and scientific interpretations are at the core of the science-policy decision-making process. Authors of peer reviewed studies are more likely to have been questioned about their methods, data interpretations, and conclusions, leading to greater confidence in the results.

In addition, the Panel was not tasked with assessing occupational studies. If CalGEM staff are aware of any peer-reviewed studies that were not included in our preliminary advice, we encourage them to send the Panel references so that we can evaluate them for inclusion in the final report. We intend to scan the literature again to assess whether relevant studies have been published since we completed the draft report. <u>Should additional peer-reviewed studies be identified, the Panel will evaluate them to determine if they align with the scope of the report and should be added</u>.

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Oil sands operations as a large source of secondary organic aerosols

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Worldwide heavy oil and bitumen deposits amount to 9 trillion barrels of oil distributed in over 280 basins around the world[1], with Canada home to oil sands deposits of 1.7 trillion barrels[2]. The global development of this resource and the increase in oil production from oil sands has caused environmental concerns over the presence of toxic compounds in nearby ecosystems[3,4] and acid deposition[5,6]. The contribution of oil sands exploration to secondary organic aerosol formation, an important component of atmospheric particulate matter that affects air quality and climate[7], remains poorly understood. Here we use data from airborne measurements over the Canadian oil sands, laboratory experiments and a box-model study to provide a quantitative assessment of the magnitude of secondary organic aerosol production from oil sands emissions. We find that the evaporation and atmospheric oxidation of low-volatility organic vapours from the mined oil sands material is directly responsible for the majority of the observed secondary organic aerosol mass. The resultant production rates of 45–84 tonnes per day make the oil sands one of the largest sources of anthropogenic secondary organic aerosols in North America. Heavy oil and bitumen account for over ten per cent of global oil production today[8], and this figure continues to grow[9]. Our findings suggest that the production of the more viscous crude oils could be a large source of secondary organic aerosols in many production and refining regions worldwide, and that such production should be considered when assessing the environmental impacts of current and planned bitumen and heavy oil extraction projects globally.

In general, secondary organic aerosol (SOA) mass is formed from the oxidation of organic gases, producing new compounds of sufficiently low saturation concentration (C*) that can nucleate or condense onto pre-existing particles. SOA typically dominates total organic aerosol (OA) mass, and can account for >50% of particulate matter mass below 2.5 μm ($PM_{2.5}$) at many locations in the northern hemisphere[10]. SOA is partially derived from the oxidation of routinely measured volatile organic compounds (VOCs; $C^* > 10^6\,\mu g\,m^{-3}$). However, recent evidence[11,12] suggests that semi-volatility compounds (SVOCs; $C^* = 10^{-1}-10^3\,\mu g\,m^{-3}$) and intermediate-volatility compounds (IVOCs; $C^* = 10^3-10^6\,\mu g\,m^{-3}$) are also important aerosol precursors owing to their high aerosol yields[13]. While oil and gas production and processing, including oil sands (OS) production, are known sources of VOC emissions[14], their SVOC and IVOC emissions are unquantified. This is particularly relevant for the OS, since the mined material is a mixture of sand, water and clay coated in bitumen, the latter being an extremely viscous (and low-volatility) form of petroleum recovered through surface mining. During the Deepwater Horizon (DWH) oil spill, SVOCs and IVOCs were the predominant precursors of SOA formed downwind of the spill[15]. Heavy oils and bitumen are comprised of lower-volatility hydrocarbons than DWH crude[16], such that their extraction and processing might be expected to release a disproportionately large fraction of SVOCs and IVOCs into the atmosphere compared to lighter crude oil. On average, $5.04 \times 10^6\,m^3\,month^{-1}$ of bitumen was produced from OS surface mining operations in 2013 (ref. 17); should it be even slightly volatilized during production, there would be a strong potential for large amounts of SOA to be formed downwind of the region. This SOA formation potential from SVOC and IVOC emissions is demonstrated later.

Three aircraft measurement flights (F1, F2, F3) were conducted in Lagrangian patterns (Extended Data Fig. 1 and Supplementary Table 1), in which the same plume from OS operations was repeatedly sampled along tracks perpendicular to the plume axis (see Methods). Each flight intercepted two large, well-mixed plumes, revealing rapid SOA formation during transport, as illustrated in Extended Data Fig. 2 for F1 (similarly observed during F2 and F3). One plume was dominated by SO_2 and sulfate aerosols and the other by OA. While the sulfur plume can be traced back to OS facility stack emissions associated with desulfurization of raw bitumen, the origin of the large OA plume was less clear, and yet OA accounted for >80% of the aerosol mass (Extended Data Fig. 2). As the aircraft flew to different downwind distances from the OS (screens A, B, C and D), peak OA mass increased from ~10 to 14 μg m^{-3} (A to B) and remained constant at ~12 μg m^{-3} (C to D), despite ongoing dilution (indicated by large decreases in SO_4^{2-} and black carbon (BC) aerosol concentrations), plume broadening (39 to 72 km) and particle deposition. This indicates a considerable SOA formation rate within these plumes, overriding the effect of dilution. Using BC as a tracer to correct for these effects (as described in Supplementary Discussion), a sixfold relative increase in OA mass (as SOA) is observed over 4 h (Fig. 1).

Net SOA formation rates were derived on the basis of mass balance using the OA mass transfer rates (tonnes (t) h^{-1}) across the flight screens[18]. The SOA formation rate is the OA transfer rate difference between screens. A description of the SOA production rate calculation, extrapolation assumptions and associated uncertainties is given in Methods. Accordingly, during F1, 3.4 ± 0.9 t h^{-1} of SOA was formed over ~90 km (A to D; Fig. 2), 2.7 ± 1.0 t h^{-1} between the screens of F2, and 2.1 ± 0.9 t h^{-1} during F3 (Extended Data Fig. 3). Including the SOA formed between the source region (S) and A, the cumulative SOA formation rates were 4.7 ± 0.9, 5.3 ± 1.0 and 4.3 ± 0.9 t h^{-1} during F1, F2 and F3, respectively. Scaling by the time-integrated OH radical concentration over daylight hours, these formation rates translate to 45–84 t day^{-1} during the summer season. These remain underestimates since they do not include deposition or SOA formation beyond the last flight screens or at night. Correcting for depositional loss increases the rates to 55–101 t day^{-1}.

The rates of SOA formation observed here are very large; the relative rate of OA enhancement depicted in Fig. 1 is comparable to downwind of megacities such as Mexico City[19] and Paris[20], and is higher than that

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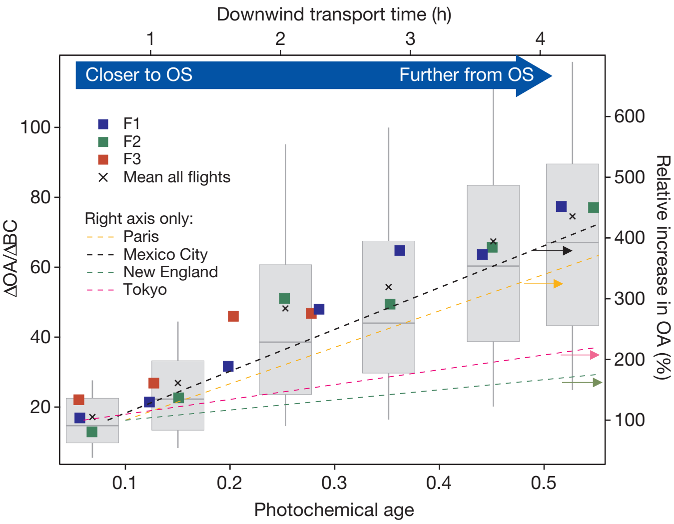
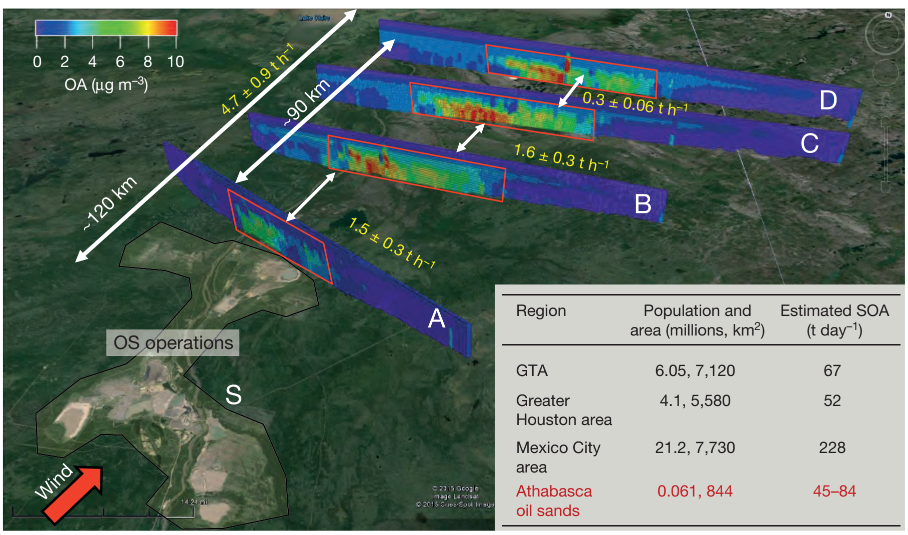


Figure 1 | Relative increase in OA downwind of the OS. The above-background (Δ)OA is normalized by BC (ΔOA/ΔBC; left axis) and shown as a function of photochemical age ($-\log(NO_x/NO_y)$; bottom axis) and air mass transport time (top axis). Increases in ΔOA/ΔBC indicate SOA formation. A sixfold relative increase in OA is observed (right axis), comparable to those reported downwind of large urban areas[19–22]. Data points represent the average of the point-by-point ΔOA/ΔBC binned by photo-chemical age. Grey boxes and whiskers represent 10th, 25th, 75th and 90th percentiles of the data from all three flights ($n = 2{,}573$).

observed in Tokyo[21] and New England[22], while the absolute rate (Fig. 2) is comparable to that estimated during the DWH oil spill (~3.3 t h^{-1}; ref. 15). However, a more compelling comparison to the absolute rate is with SOA formation rates downwind of major urban centres using available data (Fig. 2). For these urban centres, the SOA formed within one photochemical day was estimated using reported ΔOA/ΔCO ratios and daily CO emissions, assuming that CO is co-emitted with SOA precursors[23,24] (see Supplementary Discussion). The SOA formation rates downwind of the Greater Toronto Area (Canada's largest metropolis), Houston and the Mexico City Metropolitan area are estimated at 67, 52 and 228 t day^{-1} (not accounting for deposition), respectively. Despite the noted uncertainties described in Supplementary Discussion, this comparison illustrates that OS operations are one of the largest sources of anthropogenic SOA in North America.

The SOA in these OS plumes had characteristics of two types of oxygenated organic aerosols (OOA)[25] as represented by two factors derived from positive matrix factorization (PMF) analysis of aerosol mass spectrometry data. Factor 1 (Extended Data Fig. 4) was more oxygenated than factor 2 (Fig. 3a), indicating that it was more photo-chemically aged. The time series of the factors during F1 are shown in Fig. 3b. Factor 1 was regionally distributed, dominating outside the plumes (>80%) at 3–5 μg m^{-3}, and largely consisted of aged regional biogenic SOA, as its mass spectrum was highly similar to those reported over forests[26] and from monoterpene oxidation in smog chamber experiments (Extended Data Fig. 4)[27]. Factor 2 accounted for >90% of the SOA mass in the plume and was freshly formed from the oxidation of OS emissions. Its mass spectrum is almost identical to the spectra of OA derived from the OH oxidation of bitumen vapours in chamber experiments ($r^2 > 0.96$) (Fig. 3a and Extended Data Fig. 4), indicating that bitumen vapours are important precursors to the large SOA formation rates in OS plumes (see Supplementary Discussion).

The contribution of oxidized bitumen vapours to the observed SOA depends strongly on the initial volatility of the SOA precursors[11]. To assess their SOA formation potentials, the volatility distributions (VDs) of bitumen vapours evolved from OS ore were determined (see Supplementary Methods), where the VD represents the fractions of total vapour in different ranges of C*. At 20 °C, the majority of vapour evolved is in the C_{14}–C_{16} hydrocarbon range (IVOC; $C^* = 10^5$ μg m^{-3}), and shifts only slightly at 60 °C (Fig. 4a). While gaseous emissions exist that span the C_{12}–C_{18} range at ambient temperatures, heating of the material (70 °C) results in complete evaporative loss up to C_{15} (Extended Data Fig. 5), leaving primarily compounds from C_{16} to >C_{30}. This represents a volatilization of ≤15% of the total extractable hydrocarbon mass from the ore at 50 °C, increasing further at higher temperatures (Fig. 4b). In surface mining operations, ore material is obtained via open-pit mining followed by bitumen-sand separation using hot water (40–80 °C) and further refining at up to 500 °C. These derived bitumen vapour VDs clearly demonstrate the potential for atmospheric emissions of SOA precursors in a C* range associated with strong SOA formation[11,13]. On the basis of their volatility, such emissions are certain to occur during open-air mining and the various heated processing steps. Ambient ground-based measurements also show the existence of hydrocarbons



Region	Population and area (millions, km^2)	Estimated SOA (t day^{-1})
GTA	6.05, 7,120	67
Greater Houston area	4.1, 5,580	52
Mexico City area	21.2, 7,730	228
Athabasca oil sands	0.061, 844	45–84

Figure 2 | OA mass screens during F1. SOA production is estimated as the sum of the differences in OA transfer rates between screens[18]. The overall rate from the source region (S) is the integrated OA transfer rate through screen D (4.7 t h^{-1}). SOA formed within ~1 photochemical day for major North American metropolitan areas is shown in the table, compared to the range downwind of the OS (F1, F2, F3). Using ΔOA/ΔCO to derive SOA for cities has been estimated to carry −50% to +100% uncertainties[23]. GTA, Greater Toronto Area. Map data: Google, image Landsat, Cnes/Spot Image 2015.

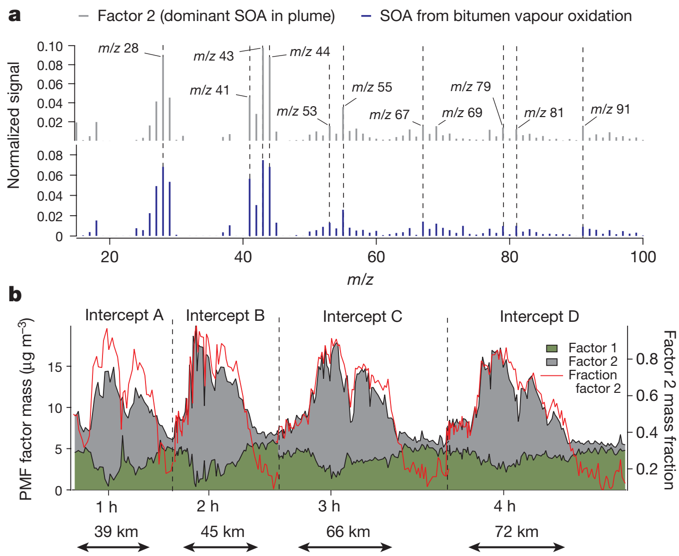


Figure 3 | PMF analysis for F1. a, PMF factor 2 profile during F1 compared to the mass spectra of SOA from the oxidation of bitumen vapours in a smog chamber, demonstrating a high degree of similarity ($r^2 = 0.96$). Signal is normalized to the total aerosol mass spectrometry (AMS) signal. **b,** Factor time series during F1 for consecutive plume intercepts approximately 1 h apart, at 600 m altitude. Factor 2 dominates the aerosol mass within the plume (red curve).

in this volatility range in plumes from OS facilities (Extended Data Fig. 6 and Supplementary Methods).

The bitumen SVOC and IVOC conversion to SOA in the observed plumes was further assessed with a Lagrangian box model constrained by the airborne measurements (Fig. 4c). The model simulated the formation of SOA in the plume of F1 over 3 h (screen A to D; Extended Data Fig. 2). Further details of the box model inputs and outputs are provided in Methods. From the ~70 p.p.b.v. of total VOCs measured at screen A, Fig. 4 demonstrates that only <6% of the SOA after 3 h was contributed by the oxidation of speciated alkanes, alkenes and aromatic

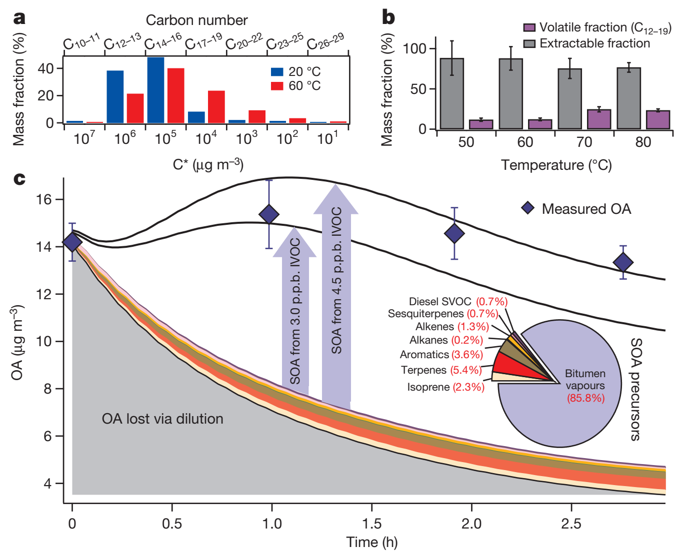


Figure 4 | Modelling SOA formation during F1. a, Volatility distribution of bitumen vapours at 20 °C and 60 °C. **b,** Fraction of the OS that is non-volatile (grey) and the volatile fraction (purple). Error bars represent standard deviation (s.d.) of $n = 3$ experiments. **c,** Box modelling of SOA formation during F1. A discrepancy between measured and modelled OA is reconciled by including 3.0–4.5 p.p.b.v. of bitumen IVOC vapours at time = 0 h (blue arrows). Error bars represent s.d. of the measured OA ($n = 7$). The pie chart indicates the contribution by each precursor type to the mass of SOA after 3 h.

hydrocarbons, and <9% by isoprene and monoterpenes. The observed OA can only be reproduced by including bitumen SVOCs and IVOCs with the VD of Fig. 4a at 20 °C; adding 3–4.5 p.p.b.v. of bitumen SVOCs and IVOCs (with the current SOA ageing scheme used) at screen A adequately simulated the SOA measurements after 3 h (contributing ~86% of the SOA; Fig. 4c). Hence, even though the required SVOC and IVOC concentrations may be small (3–4.5 p.p.b.v.) compared to ~70 p.p.b.v. for VOCs, they dominate the contributions to SOA formation. Such a high SOA formation intensity is in contrast to most other types of energy production, which are likely to have emissions in a much lighter hydrocarbon range[28,29].

The evidence here indicates that large amounts of SOA will form from this previously unrecognized pool of OS-emitted SVOCs and IVOCs, dominating over SOA from traditional VOC precursors. The potential air-quality impacts of these vapours as a result of transport and refining could be more widespread than anticipated. Indeed, recent evidence indicates that primary IVOCs from an unknown petroleum-based source can account for about 30% of SOA mass in urban/suburban areas[12]. This issue is not limited to Canada, as Venezuela plans to develop its Orinoco Oil Sands recoverable reserve of ~300 billion barrels, and the USA—having an estimated 54 billion barrel reserve of bitumen—has begun surface mining in Utah. In light of the current trend for increasing heavy oil production relative to conventional crude, further investigation is required to fully understand the magnitude of this potential global issue.

Online Content Methods, along with any additional Extended Data display items and Source Data, are available in the online version of the paper; references unique to these sections appear only in the online paper.

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Supplementary Information is available in the online version of the paper.

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Author Contributions All authors contributed to the collection of observations in the field, in the laboratory or the development of the box model. J.L. and S.-M.L. wrote the paper with input from all co-authors. S.-M.L. designed and directed the flights. Y.M.T. and C.S. conducted the box modelling work with input from J.L. D.R.G., D.P., B.D.D. and P.L. provided bitumen volatility distributions.

Author Information The data used are available on the Canada-Alberta Oil Sands Environmental Monitoring Information Portal (http://jointoilsandsmonitoring.ca/default.asp?n=5F73C7C9-1&lang=en). Reprints and permissions information is available at www.nature.com/reprints. The authors declare no competing financial interests. Readers are welcome to comment on the online version of the paper. Correspondence and requests for materials should be addressed to J.L. (John.Liggio@canada.ca) or S.-M.L. (Shao-Meng.Li@canada.ca).

METHODS

Aircraft campaign. Airborne measurements of an extensive set of air pollutants over the Athabasca oil sands region in northern Alberta were conducted between 13 August and 7 September 2013 in support of the Joint Canada-Alberta Implementation Plan on Oil Sands Monitoring. Instrumentation was installed aboard the National Research Council of Canada Institute for Aerospace Research (NRC Aerospace) Convair-580 research aircraft. The aircraft flew 22 flights over the Athabasca oil sands, for a total of approximately 84 h. Thirteen flights were designed specifically to quantify area emissions from various OS facilities by flying in a rectangular box shape, at multiple altitudes, resulting in 21 box flights around 7 different OS facilities.

A further three flights (denoted F1 (4 September), F2 (5 September) and F3 (19 August)) were designed to study the transformation of OS emitted pollutants, including the formation of SOA. These flights were designed as Lagrangian experiments in which the same air parcels in OS plumes were sampled at different time intervals (1 h apart) as the air parcels were transported downwind for 4–5 h. The measurement locations for the flight tracks were chosen so that the aircraft would intercept the same air parcel, using real-time wind speed/direction measurements to guide the intercept locations. The intercepting flight tracks were perpendicular to the axis of the plumes, and the flight times crossing the plumes were 5–7 min. At each intercept location, high time resolution (1 s for gases, 10 s for AMS measurements) measurements were made at multiple altitudes (2–5 horizontal transects) from ∼150 m above ground to over 1,400 m, which was higher than the mixed layer height, consisting of level flight tracks and spirals at the centre of the plume. These vertically spaced level flight tracks and spirals constituted virtual screens at the intercept locations. The three flights (F1, F2 and F3) comprised 5, 3 and 3 screens, respectively. In between the screens in each flight, there were no industrial emissions. Thus, changes between screens can be described in terms of mixing/dilution, chemistry and deposition that occurred from within a single air parcel.

The first screens of the F1, F2 and F3 flights were approximately 1 h downwind of the majority of OS facilities, and at distances that pollutants from multiple OS sources were well mixed and merged into large plumes. The flight paths and their associated parameters are given in Extended Data Fig. 1 and Supplementary Table 1. As shown in this figure, the Lagrangian experiments resulted in varying degrees of success for a number of reasons, including data capture rates, consistency of winds, and the exact timing of when the aircraft crossed the plumes at the chosen intercepting locations, with F1 having the best matches between the air parcel transport times and the aircraft flight times at the screen locations. As a result, the data from F1 are used more extensively than others here, although not exclusively.

The Convair-580 was equipped with fast response instrumentation to measure an extensive set of gas- and particle-phase pollutants, as well as standard meteorological and aircraft state parameters. A description of the meteorological variables and aircraft state parameters measured is given elsewhere[18]. Non-refractory (NR) particle composition (that is, ammonium, nitrate, sulfate and organics) was measured with an Aerodyne high-resolution time-of-flight aerosol mass spectrometer (HR-ToF-AMS; Aerodyne Research)[30]. Refractory black carbon (BC) particle measurements were made with a Single Particle Soot Photometer (SP2; Droplet Measurement Technologies)[31,32]. A subset of volatile organic compounds (VOCs) was measured with a high-resolution proton transfer time-of-flight mass spectrometer (PTR-ToF-MS; Ionicon Analytik GmbH)[33] and a more extensive set of hydrocarbons was measured via on-board canister sampling, followed by analysis by gas chromatography mass spectrometry and flame ionization detection (GC–MS and GC-FID). A full description of all the relevant gas- and particle-phase instrumentation aboard the aircraft is provided in the Supplementary Information. No statistical methods were used to predetermine sample size.

OA mass transfer rate and OS SOA production rate calculations. The quantification of the mass transfer rate of organic aerosols (R_{OA}, in t h^{-1}) across a virtual screen uses an extension of the top-down emission rate retrieval algorithm (TERRA) described previously[18]. TERRA was originally developed to determine emission rates from box flight patterns during this study[18], based on mass balance within the virtual box constructed from the flight tracks. Briefly, TERRA uses the flight path around a facility at multiple altitudes to map the data to the two-dimensional virtual walls of a box surrounding the facility. The transport of a pollutant through the walls is calculated using aircraft wind and compound mixing ratio measurements, and emission rates calculated on the basis of the divergence theorem with estimations of box-top loss rates, horizontal and vertical advective and turbulent transport rates, surface deposition rate, and apparent loss rates due to air densification and chemical reaction rates. For the transformation flights, some components of TERRA were extended to apply to single screens created from vertically stacked level flight tracks and spirals. Concentration data C (in μg m^{-3}) are mapped to the screens and interpolated using a simple kriging function (on approximately 5,000–15,000 individual data points). Wind speed along the flight tracks was decomposed into two components based on the wind direction, one parallel to the screen (u_p) and the other normal to the screen (u_n), and the decomposed wind speeds were similarly mapped to the screen and interpolated using kriging. The lowest flight altitude was at approximately 150 m, hence there was a need to extrapolate the OA measurements and the wind speed components downward to the ground surface. The downward extrapolation for the wind speed components assumed a stability-dependent log profile[34] vertically and uses nearby concurrent wind profiler data to determine the roughness and displacement height[18]. The OA measurement downward extrapolation was based on the assumption of a well-mixed layer below the lowest flight track altitude, which is consistent with modelling[35] and the potential temperature profile. A variation to this downward extrapolation method assumed a linear downward trend from the flight altitudes, to capture possible variations in the mixing state below the lowest flight track altitude. Previous analysis has shown that unknown pollutant concentrations below the lowest flight level (and the associated extrapolation to ground) led to the majority of the uncertainty in the emissions estimates from this approach (∼20%; ref. 18). The OA measurements during the flights here were extrapolated downward using both methods; varying linearly to the ground or held constant (at the lowest altitude concentration) to the ground, to assess the uncertainty in the final derived mass transfer rate caused by the extrapolation methods. The OA data were further linearly extrapolated from the highest altitude level flight tracks upwards (to background OA concentrations) in the case where the level flight tracks did not traverse vertically beyond the mixed layer. The highest altitude extrapolated to was determined from the OA measurements and temperature profiles from spirals along the tracks, which were flown above the top of the boundary layer but not included in the screens. The results showed a difference of <15% for the mass transfer rates among the different extrapolation schemes.

The mass transfer rate of OA across each screen (R_{OA}) of flights F1, F2 and F3 was derived on the basis of the extended TERRA as described earlier and the HR-ToF-AMS data. To avoid the background OA affecting the computation of R_{OA}, a background OA (Extended Data Fig. 7) was subtracted from the OA measurements in the following computation:

$$R_{OA}(A) = \int_{s_1}^{s_2}\int_{z_1}^{z_2} C(s,z,A)\,u_n(s,z,A)\,\mathrm{d}s\,\mathrm{d}z \quad (1)$$

where s_1 and s_2 are the horizontal edge positions on the screen for the plume containing OA, z_1 is the ground surface altitude, z_2 is the top of the plume, $C(s,z,A)$ is the interpolated/extrapolated concentration on screen A (and other screens), and $u_n(s,z,A)$ is the interpolated/extrapolated wind speed vector normal to screen A. The plume edges are determined by the OA concentration on the screen, indicated by $C(s,z,A)$, approaching the background concentration of approximately 4 μg m^{-3}. Note that equation (1) describes horizontal advective transfer rates only; additional contribution from horizontal turbulent fluxes can contribute to R_{OA} but this has been shown to be a few orders of magnitude smaller than the horizontal advective transfer[18] and therefore is ignored henceforth.

Between screens, the mass transfer rate R_{OA} may change due to emissions with a rate of E_{OA}, deposition with a rate of D_{OA}, and the formation of SOA at a rate of R_{SOA}. In the original TERRA, vertical advective and turbulent transfer rates as well as air density changes were considered to achieve mass balance when the background level of a compound was large[18]. The vertical transport term was nominally small compared to the horizontal advection, and hence can be ignored. Thus, using a mass balance approach, the following relationship can be established

$$R_{OA}(t_2) = R_{OA}(t_1) + R_{SOA} + E_{OA} - D_{OA} \quad (2)$$

where t_1 and t_2 are the times of the two screens where the plume parcels were intercepted. Positive matrix factorization (PMF) analysis of the HR-ToF-AMS data from the transformation flights F1, F2 and F3 showed no hydrocarbon-like aerosol factor[25], suggesting small-to-non-existent contributions from primary emissions of organic aerosols between the screens or from the source region to the screens. Hence $E_{OA} = 0$. Using concurrent refractory BC measured by SP2, the maximum dry deposition of BC over the region was estimated to be approximately 7% h^{-1} derived from the differences in the BC mass transfer rates across the screens. We assume that this rate of deposition of BC is applicable to OA. Since deposition derived this way is relatively small, it is ignored to derive the SOA formation rate according to

$$R_{SOA} \approx R_{OA}(t_2) - R_{OA}(t_1) \quad (3)$$

Equation (3) was used to calculate the SOA formation rates, ignoring the dry deposition term, to be comparable to urban SOA estimates, which are net of deposition. Including a fully evaluated dry deposition for the R_{SOA} calculation would mean that equation (3) gives a lower limit of the true SOA formation rate during the measurement period. The total SOA production rate (R_{SOA}) in these flights is taken to be the

OA transfer rate (R_{OA}) through the final screen, since $E_{OA} = 0$ and only oxygenated PMF factors were observed. The total SOA is then extrapolated to a photo-chemical day as described in Supplementary Discussion (Extended Data Fig. 8).

Box modelling description. SOA formation in the large-scale plume of F1 was modelled with a zero-dimensional Lagrangian box model, as it evolved over approximately 3 h (~600 m altitude). The simulation was constrained by the measurements of VOCs, NO_x, OVOCs, O_3 and other parameters, while dilution within the plume was accounted for using BC as a dilution tracer. Hydrocarbons of both anthropogenic and biogenic origin were constrained at the first screen (A), or throughout the simulation for those biogenic species with potential continuous emissions along the flight track (monoterpenes and isoprene). Background concentrations were constrained by measurements outside of the plume. The model uses the Statewide Air Pollution Research Centre (SAPRC07) chemical mechanism with updated isoprene chemistry[36–38]. The model was run with a 2 min time step and diluted chemical species at every time step. While the model had VOCs constrained, including a constraint for NO_x and O_3 resulted in very little difference between the model and observations. Hence, the gas-phase chemistry is well simulated by the box model, as shown in Extended Data Fig. 9. Sesquiterpenes were constrained based on the ratio to measured monoterpenes. Sesquiterpenes were estimated from the PTR-ToF-MS measurements using an estimated ion transmission efficiency and proton transfer reaction kinetics, in a manner described previously[39,40], resulting in a sesquiterpene:monoterpene ratio of ~0.39. This is somewhat higher than the ratios of 0.013 and 0.105 that have been recommended previously[41,42], and was used as an upper estimate to the sesquiterpene contribution to SOA. Regardless, biogenic VOCs contributed little to the observed and modelled SOA (Extended Data Fig. 10 and Supplementary Discussion). Recent evidence has also suggested that extremely low-volatility compounds (ELVOC) can also form via an auto-oxidation mechanism[43]. This process has been demonstrated to be most relevant in rural and remote regions where OA loading, VOC and NO_x levels are very low, due to competing $RO_2 + NO$ and/or $RO_2 + RO_2$ reactions. Previous data[43] indicate that ELVOC yields are most important at 1 p.p.b.v. NO_x and below. While ELVOC may be an important SOA contributor outside of the OS plumes (where biogenics are abundant and NO_x is low), the amount of NO_x in the OS plumes studied (as well as the OA loading and VOC levels) were far too high (approaching >20 p.p.b.v. NO_x and always greater than 1 p.p.b.v.) for ELVOC formation to be important. Hence, the contribution of ELVOC was not explicitly included in the box model analysis.

Additionally, the model incorporated SOA formation from all known SOA precursors[24] treating SOA formation in two separate volatility basis sets (VBSs) (see supplementary Methods). Following a previously described method[24], a four-bin VBS ($C^* = 1$, 10, 100 and 1,000 $\mu g\,m^{-3}$) treated SOA formation from traditional volatile organic compounds (VOCs), while a second nine-bin VBS ($C^* = 10^{-2}$–$10^{6}\,\mu g\,m^{-3}$) treated SOA from SVOCs and IVOCs. The four-bin VBS was used for SOA from traditional VOCs including long-chain alkanes (ALK5 in SAPRC07), olefins (OLE1 and OLE2), aromatics (ARO1, ARO2, NAPTH and benzene), and biogenic compounds (ISOP, TERP and SESQ (isoprene, monoterpenes and sesquiterpenes)[24,44] The nine-bin VBS treated 'non-traditional' SOA formed from the oxidation of off-road diesel as well as bitumen vapours having a volatility distribution as shown in Fig. 4a at 20 °C. This volatility distribution was chosen to represent the emissions of these vapours at ambient temperature that would be expected for the first aircraft screen at ~600 m above ground, assuming that the open-pit mines are the largest contributor to emissions. A contribution by other processes at higher temperature is also possible. Total non-methane hydrocarbon (NMHC) mixing ratios in the plume were estimated based on the emission ratios of CO:NMHC from the heavy hauler diesel engines used in the Alberta OS facilities and the difference between CO in the plume and CO in the background (ΔCO). The emission ratios of SVOCs and IVOCs relative to total NHMC that were reported previously[39] for diesel engines were then applied to the total NMHC to give an estimate of the SVOCs and IVOCs in the plume. Pentadecane was used as a surrogate species for the SVOC and IVOC species from diesel emissions as suggested previously[44].

The model is configured in such a way that the initial reaction of a SOA precursor with OH (or O_3 in the case of ISOP, TERP, OLE1 and OLE2) leads to the formation of a number of less volatile gas-phase species. These less volatile gas-phase species are placed in volatility bins according to fitted chamber results[45]. The species in each of the bins are then allowed to partition between the gas and particle phase in accordance with their temperature-dependent partitioning coefficients[24,45]. To mimic aerosol ageing, the gas phase components in both the VOC SOA (V-SOA) and semi- and intermediate-volatility SOA (SI-SOA) VBS are aged as described previously[24]. Specifically, traditional SOA in the V-SOA VBS is aged according to the Robinson *et al.* scheme[46], while SOA in the SI-SOA VBS is aged according to the more aggressive Grieshop scheme[47]. The Robinson scheme used to age V-SOA adds 7.5% more mass to the SOA during oxidation while moving the species to a volatility bin 10 times less volatile. The Grieshop scheme[47] that was used to age the SI-SOA adds 40% more mass per oxidation but shifts the species to a volatility bin 100 times less volatile. As the majority of the SOA formed in the V-SOA VBS is formed from anthropogenic precursors, V-SOA was aged at a rate of $1 \times 10^{-11}\,cm^3\,molecule^{-1}\,s^{-1}$ (refs 48, 49). The SOA in the SI-SOA VBS was aged using a faster rate of $2 \times 10^{-11}\,cm^3\,molecule^{-1}\,s^{-1}$ (ref. 24). The use of two separate ageing schemes for SOA formation is consistent with the expected differences between product distributions, molecular size and functional groups of different classes of precursor organic compounds. Such an approach has been used successfully on numerous occasions to match SOA observations (see Supplementary Methods). Further model runs were also performed to examine the sensitivity of the SOA formed from IVOCs to the oxidation scheme used (Extended Data Fig. 9 and Supplementary Methods). On the basis of these further model runs, the chosen base case conditions provide the best estimate of the SOA formation rate as it lies between the two upper and lower limits and is consistent with the scheme used in numerous regional air quality models that reasonably reproduce ambient forested and urban observations around the world.

The model output was compared with organic aerosol observations. While the HR-ToF-AMS effectively measures $PM_{1.0}$, the condensation of oxidized products will occur across the entire size distribution. Considerable coarse particle mass is observed during flight 1, probably originating from the large trucks during mining operations. Since the box-model output is a bulk SOA value (that is, size independent), the AMS-derived OA mass is further increased using the measured surface area ratio of $PM_{1.0}$ to PM_{20}, assuming that the condensation process is approximately proportional to surface area. This ratio, which ranged from ~1.3 to 1.1 from screen A to screen D, was multiplied by the AMS-measured OA, increasing the total OA by 10–30% for comparison to the model output.

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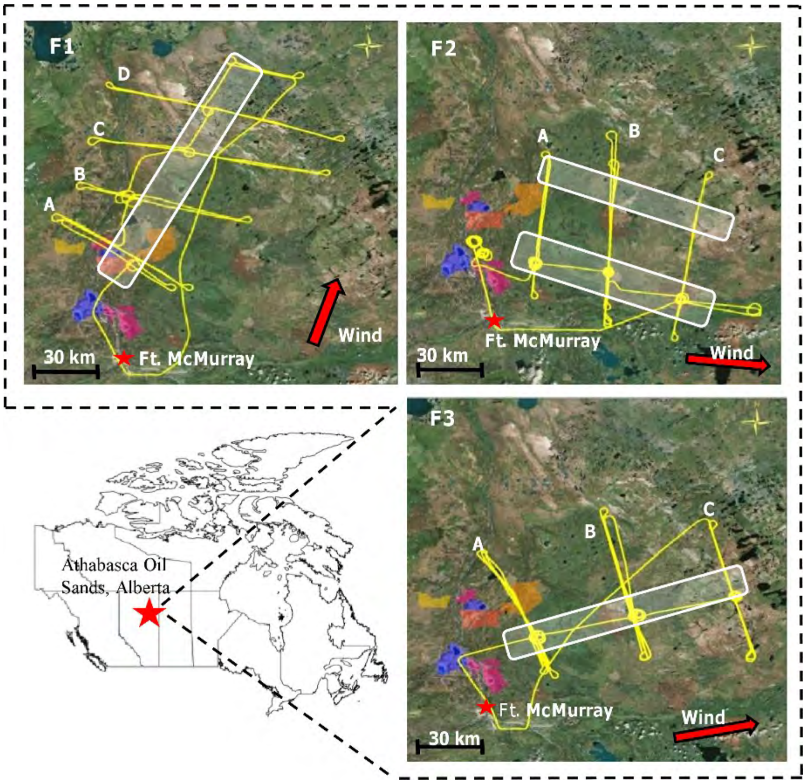
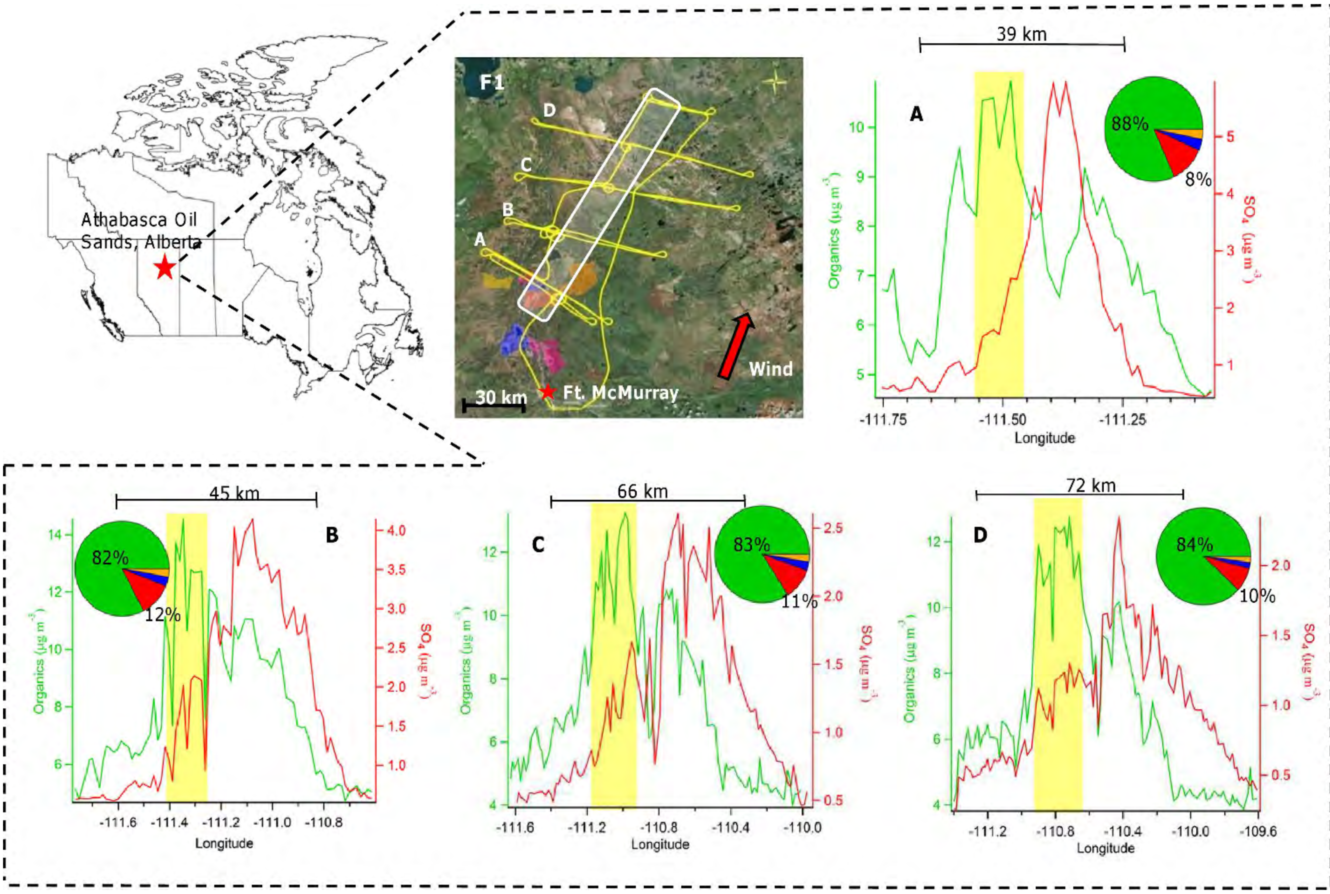
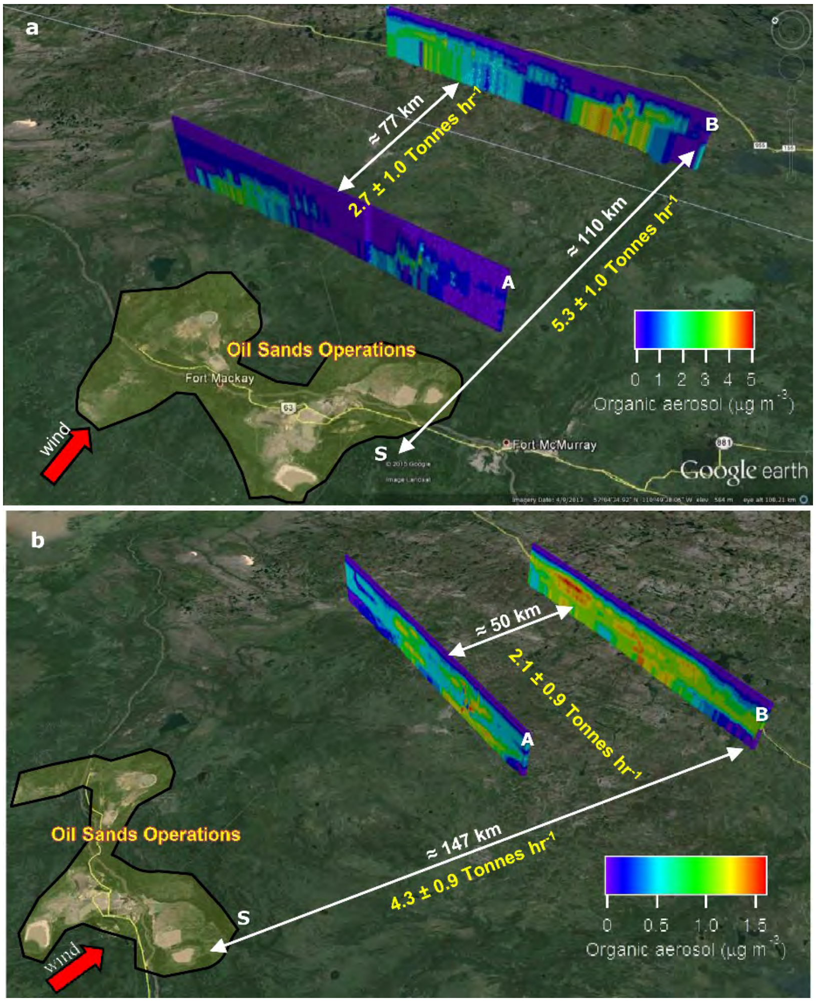


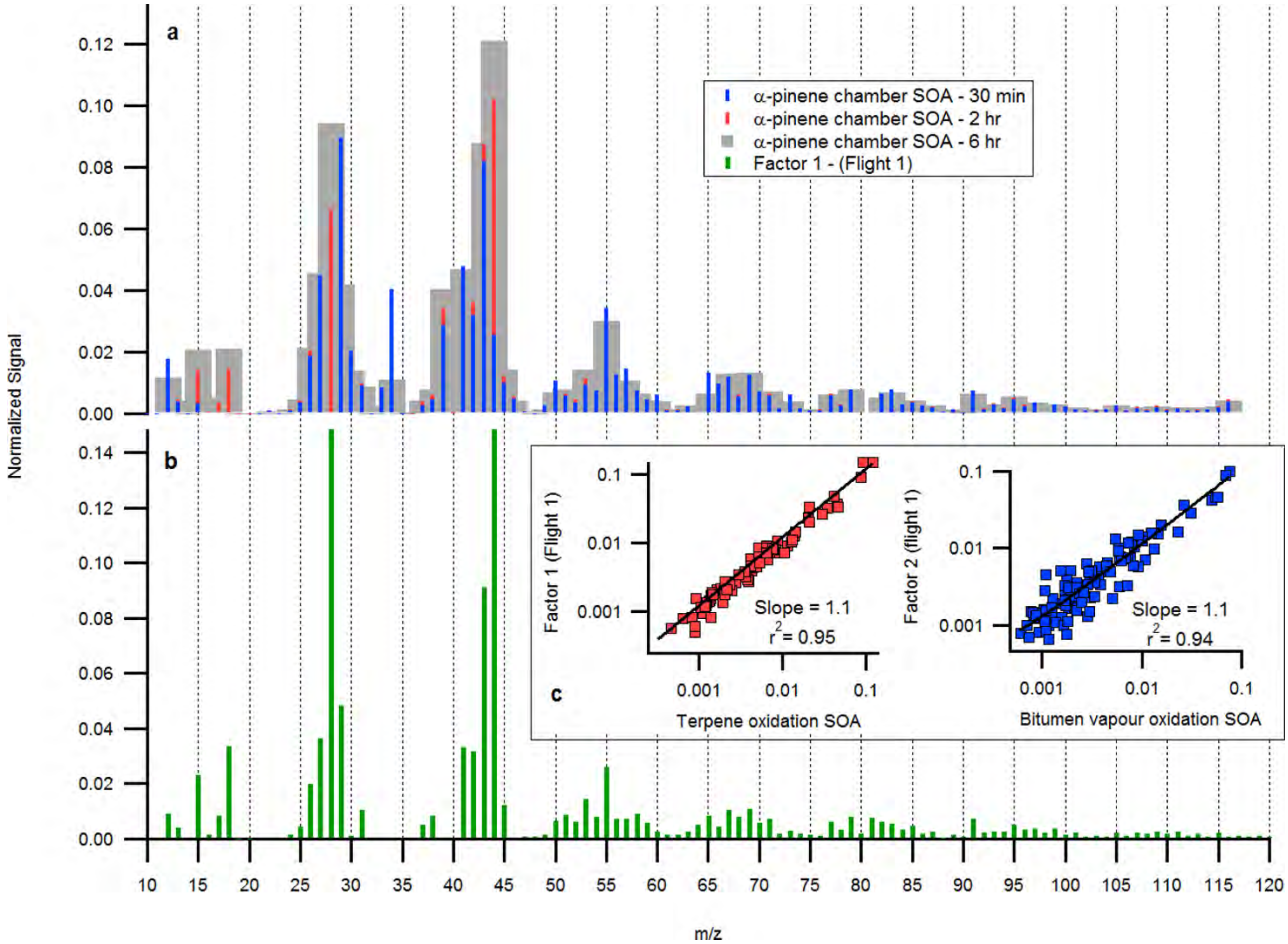
Extended Data Figure 1 | Flight tracks for the three transformation flights, F1, F2 and F3. The approximate locations of the major OS plumes studied in this work are shown as the white shaded boxes. Map data: Google, image Landsat, 2015.



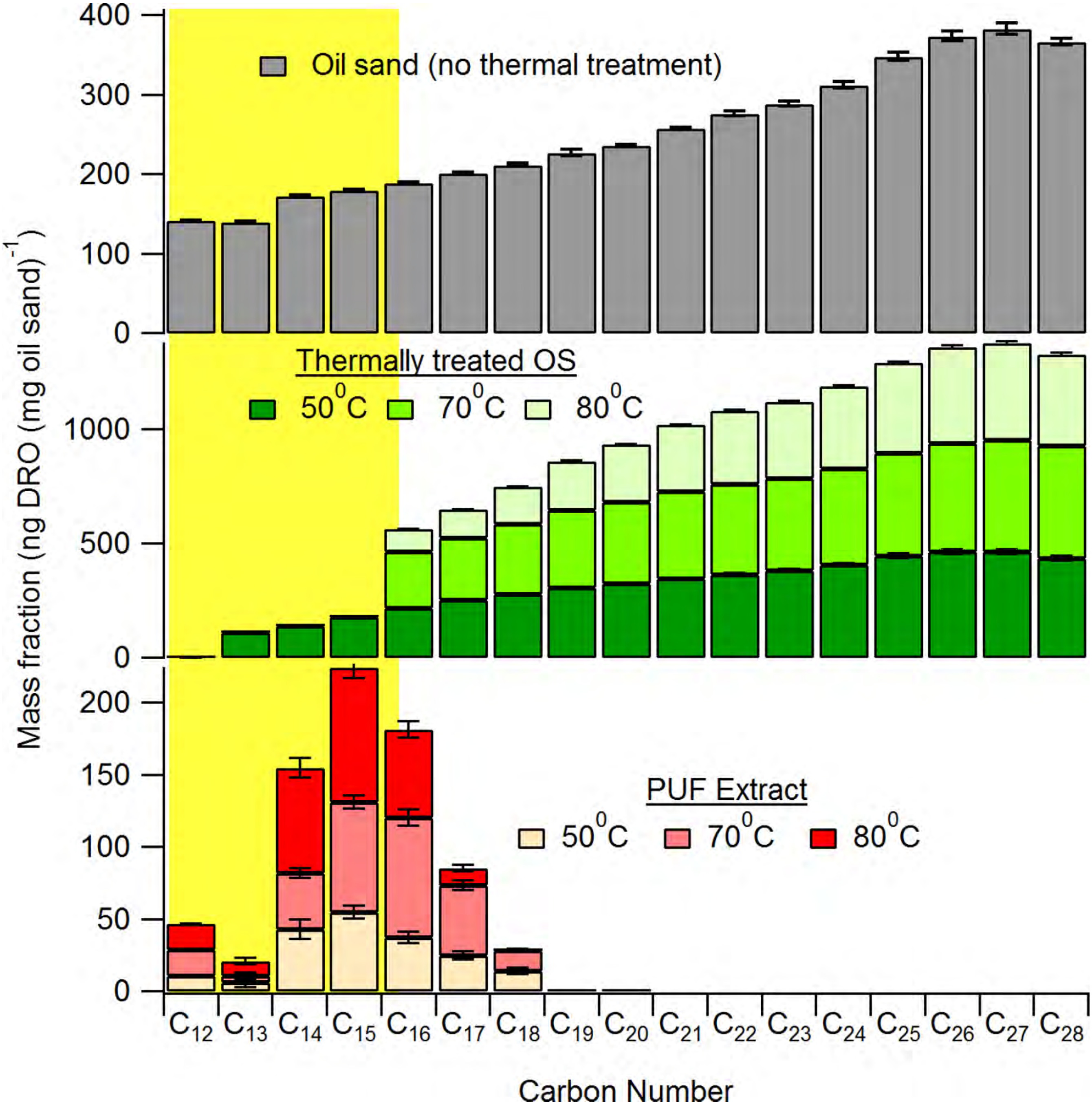
Extended Data Figure 2 | Measured organic and sulfate aerosol concentration during F1. Successive transects (labelled A, B, C and D) through the same major OS plumes at approximately 600 m altitude and 1 h apart in transit time. Inset pie plots show the mean relative mass fraction for organics (green), sulfate (red), nitrate (blue) and ammonium (orange) during the yellow highlighted section. Organics dominate the aerosol mass throughout the flight; note the change in magnitude between the OA scale on the left and SO_4 scale on the right. Map data: Google, image Landsat, 2015.



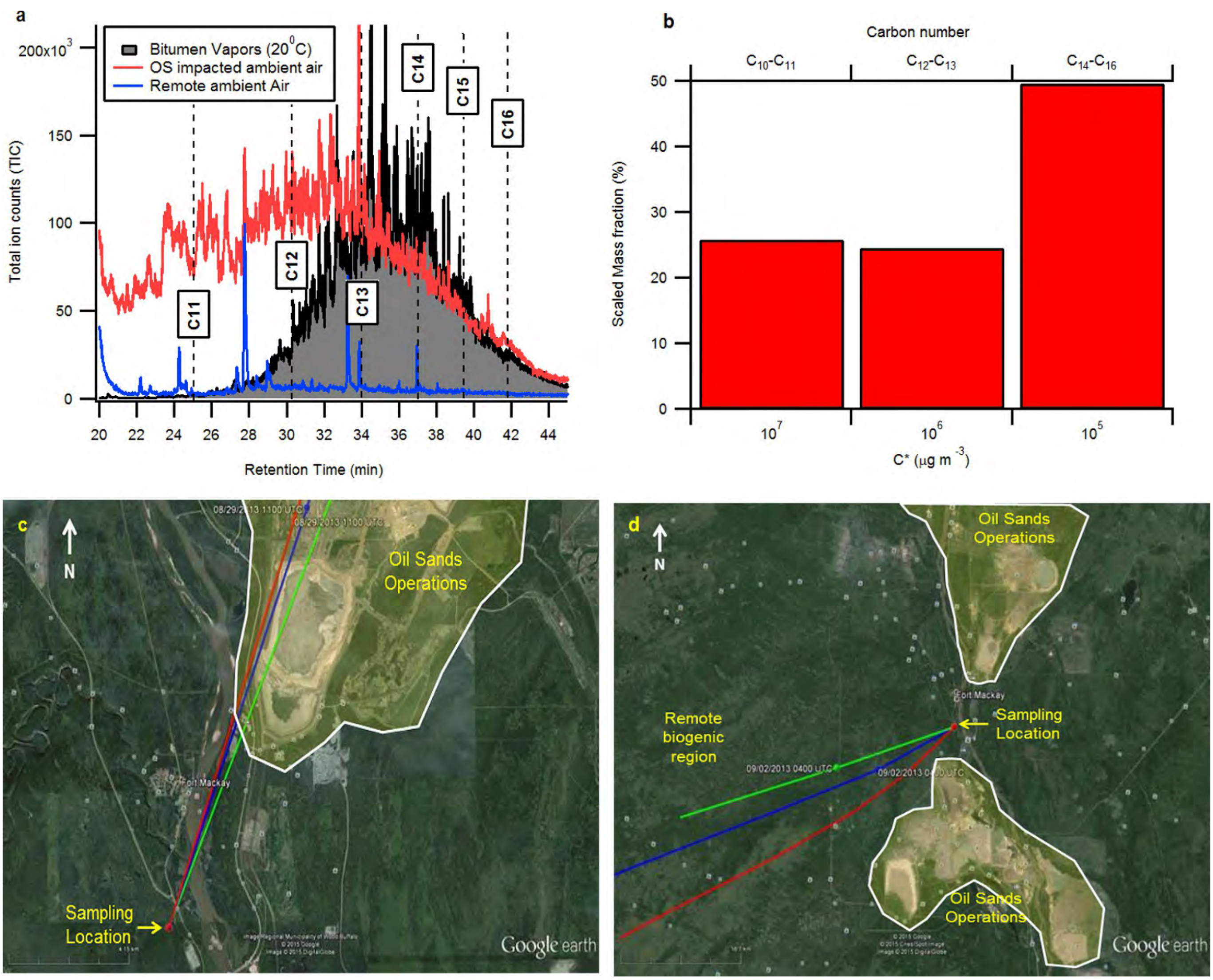
Extended Data Figure 3 | OA mass screens used to estimate SOA production. a, **b**, OA mass screens for F2 (**a**) and F3 (**b**). The SOA production rate during these flights (~77 km and ~50 km between screens) is the sum of the differences in OA transfer rates between screens (that is,: 2.7 ± 1.0 t h^{-1} and 2.1 ± 0.9 t h^{-1}). The overall formation rate from the OS source region (S) is the integrated OA transfer rate through screen B (5.3 ± 1.0 t h^{-1} and 4.3 ± 0.9 t h^{-1}). Map data: Google, image Landsat, 2015.



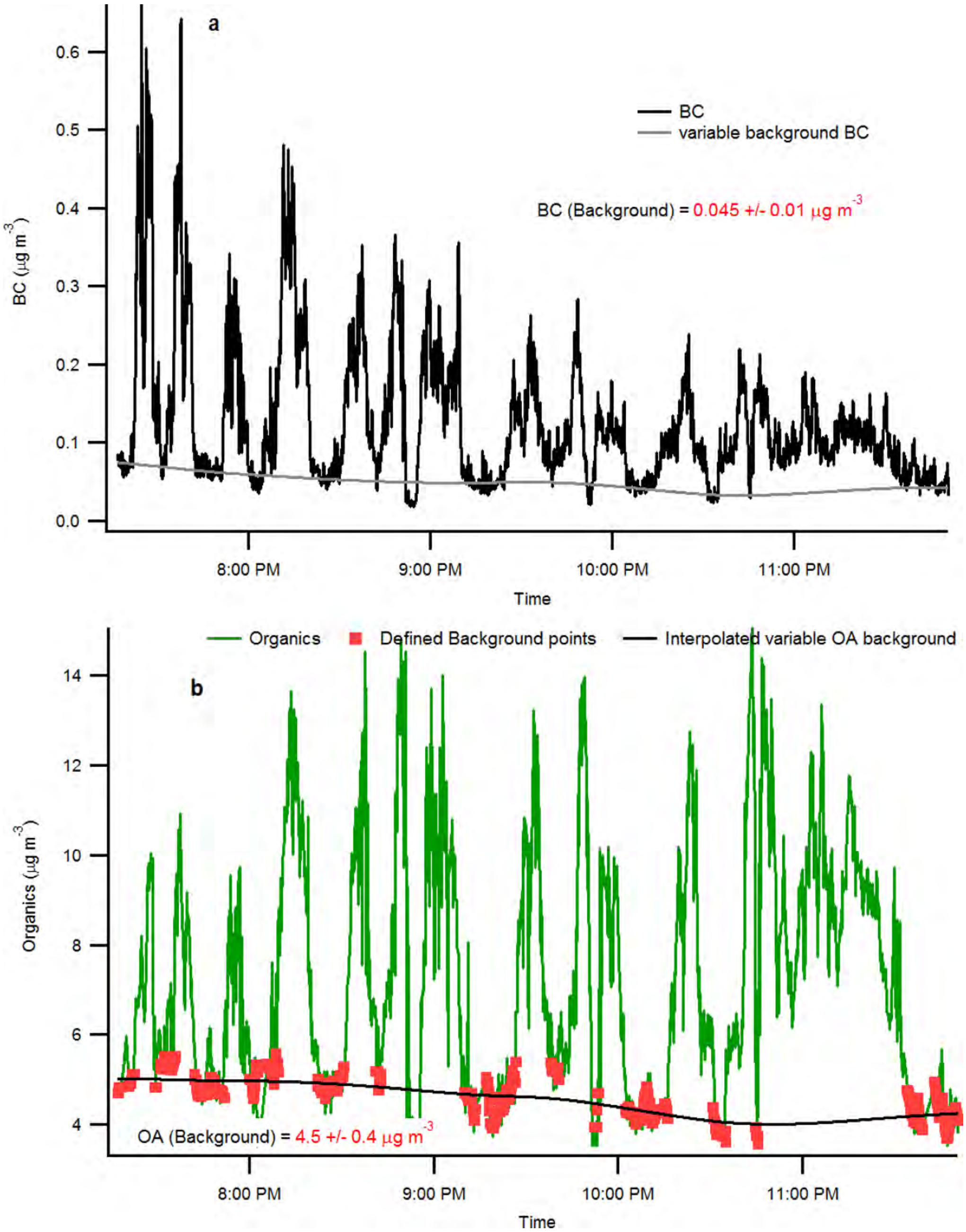
Extended Data Figure 4 | PMF analysis results and comparisons. **a**, The OA AMS spectra from an α-pinene + OH radical smog chamber experiment as a function of photochemical ageing time in the chamber. **b**, PMF factor 1 from F1. A high degree of similarity is observed between these spectra after approximately 6 h of ageing in the chamber. **c**, Correlations between PMF factors 1 and 2 and the corresponding smog chamber data (terpene oxidation and bitumen vapour oxidation SOA).



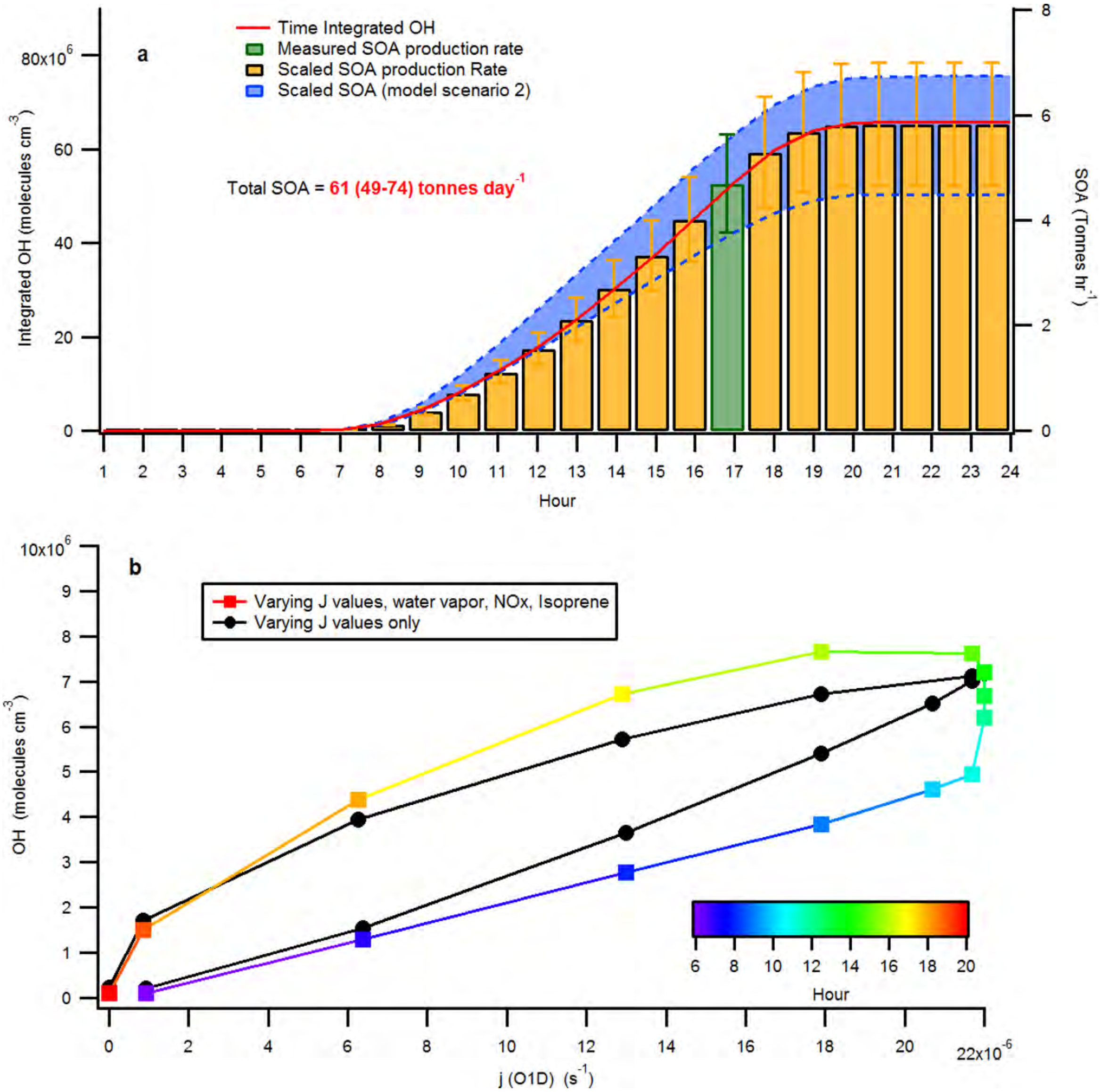
Extended Data Figure 5 | Bitumen volatility distributions. The volatility distribution (mass fraction) based on carbon number are for OS that was thermally treated. Volatile hydrocarbons are trapped on polyurethane foam (PUF) tubes at 50–80 °C (red). The volatility of the remaining bitumen material is shown in green (50–80 °C) and that of bitumen which was solvent extracted from the sand without heating is shown in grey. Note the complete loss of hydrocarbons in the C_{12}–C_{15} range upon heating (denoted in yellow). Data are stacked upon each other for clarity. Error bars represent the s.d. of $n = 3$ experiments.



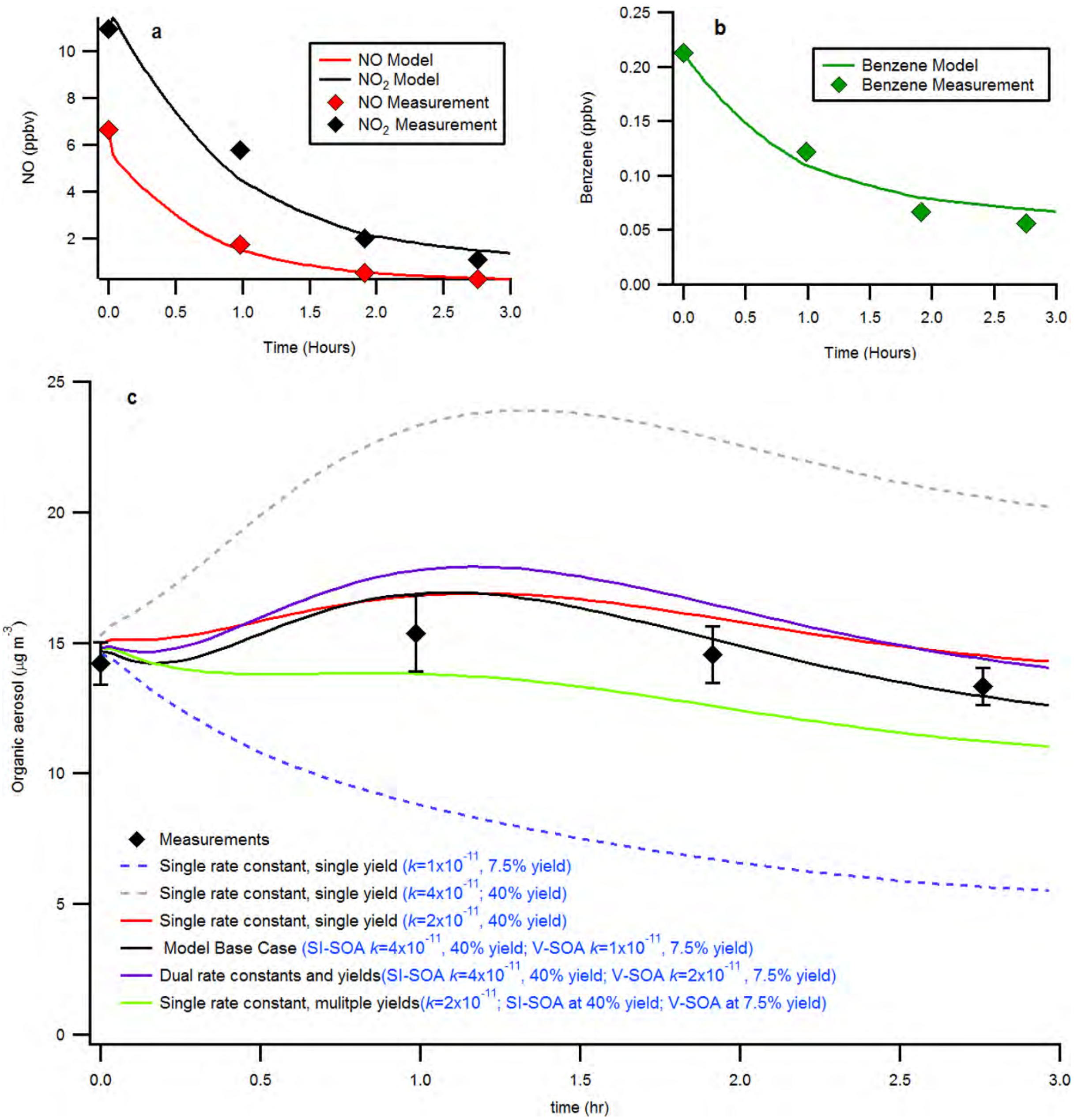
Extended Data Figure 6 | Bitumen-related IVOCs in ambient ground-based data. a, Total ion chromatogram from ambient sampling in the OS when impacted by forest-influenced air (blue) and OS-operations air (red). The bitumen vapour headspace chromatogram is also shown (black), demonstrating that a large fraction of the gaseous mass in OS-impacted air has volatilities (C_{13}–C_{16} range) critical for SOA formation. **b**, Associated volatility distribution for OS-impacted air scaled by SOA yield[11]. **c**, One-hour back trajectory for OS-impacted sample using the hybrid single particle Lagrangian integrated trajectory model (HYSPLIT). **d**, One-hour HYSPLIT back trajectory for forest-influenced sample.



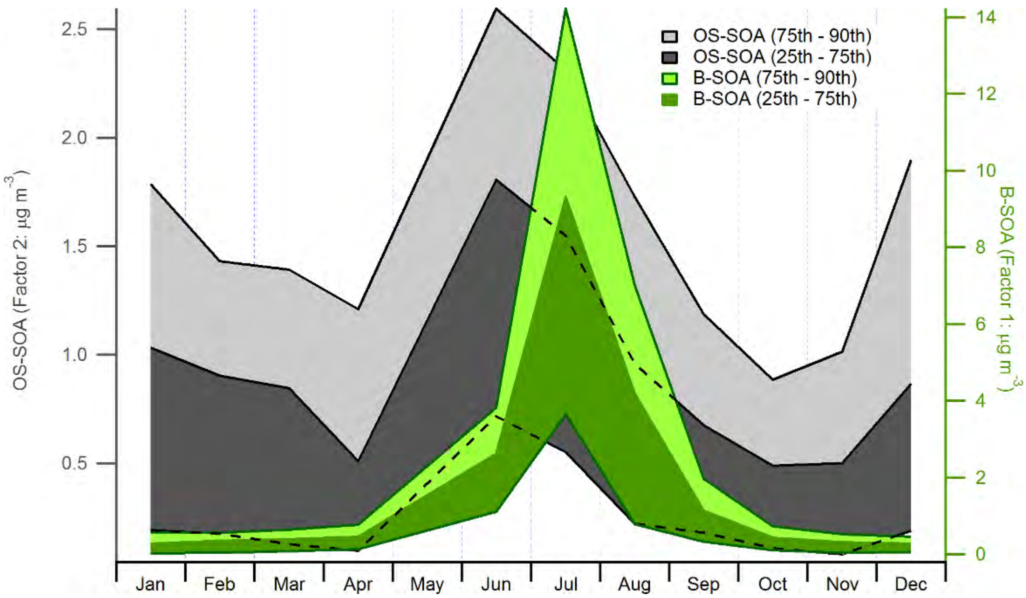
Extended Data Figure 7 | Background concentration time series. a, b, The BC (**a**) and OA (**b**) time series for F1 with associated interpolated backgrounds. The background variability contributed little uncertainty to the overall analysis of ΔOA/ΔBC in Fig. 1.



Extended Data Figure 8 | SOA production rate extrapolation. **a**, Measured SOA for F1 extrapolated to one photochemical day. Total SOA production is the sum of scaled hourly SOA production rates (orange; see Supplementary Methods). The blue region represents the same scaling performed where only photolysis rate constants are varied in the model. Error bars represent a range of SOA estimates assuming ±20% on the initial OA estimates via the TERRA algorithm. **b**, Modelled dependence of OH radical concentration on the ozone photolysis frequency (JO^1D). Further varying initial conditions for NO_x, water vapour and isoprene in the model has a small effect on this relationship.



Extended Data Figure 9 | Box-model performance evaluation. **a**, **b**, Measured and modelled gas-phase species during plume intercepts of F1, where only the initial conditions ($t = 0$) of the species are constrained by measurements. Good agreement between model and observation is achieved. **c**, Sensitivity of predicted SOA for F1 to changes in the oxidation rate constant and yield (all other variables remain constant). Yield refers to the SOA mass yield during the oxidative ageing. Simulations using a single oxidative rate constant and yield represent upper and lower limits to SOA formation, while the base case simulation most closely resembles measurements. Error bars represent s.d. of the measured OA ($n = 7$).



Extended Data Figure 10 | PMF factors from ground-based data in the OS. PMF factors 1 (biogenic SOA (B-SOA)) and 2 (OS-SOA) from 1 year of ground-based data in the OS production region (monthly 25th to 90th percentiles shown, $n = 22{,}280$), indicating that factor 2 (using a collection efficiency of 1) is derived from the oxidation of OS emissions all year long, while factor 1 is from oxidation of biogenic emissions (that is, summer peak only).

An oil field in Kern County, California, where producers rely on steam injection to pump out thick, carbon-heavy crude. MARK RALSTON/AFP/GETTY IMAGES

Why Does Green California Pump the Dirtiest Oil in the U.S.?

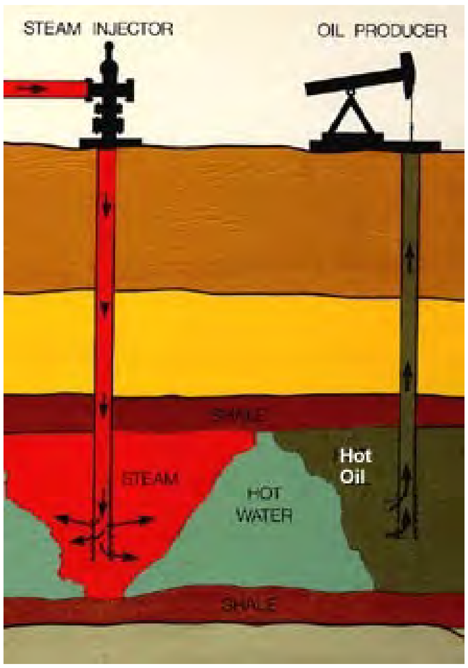
BY JUDITH LEWIS MERNIT • OCTOBER 19, 2017

California may be a leader in climate policies, but much of its abundant oil reserves are nearly as carbon-intensive to extract and refine as Alberta tar sands crude. Many experts now say that reform of the state's methods of producing oil is long overdue.

On New Year's Day, 1909, a grocer named Julius Fried and his novice drilling crew, the Lakeview Oil Company, spudded a well in the desert valley scrub in the Midway-Sunset oil field, 110 miles north of Los Angeles. For the first 1,655 feet, the well yielded only dust, and then Lakeview ran out of money.

Fried must have gone to his grave wishing his crew had held on just a little longer. On March 14, 1910, the Union Oil Company's Charlie Woods – nicknamed "Dry Hole Charlie" for his long streak of dusters – struck what he would later describe as an "artery in the earth's great storehouse of oil." When his drill bit reached 2,225 feet beneath the surface, Lakeview No. 1 sent up a sudden column of pressurized oil 200 feet into the air. For 544 days, the Lakeview Gusher would defy every effort to contain it, eventually spreading 9.4 million barrels of oil across the valley floor. Less than half of it was recovered. It remains, to this day, the largest oil spill in the history of the world.

No more gushers spring forth from Midway-Sunset, in California's parched and scoured San Joaquin Valley. Most of the reserves that rose to the surface like a milkshake through a straw have long since been tapped. What remains are thick hydrocarbons heavy with carbon and depleted of hydrogen, stuck in tectonic rifts that conventional rigs can't penetrate. Some of it can be coaxed out by first cracking the rock open with an injection of chemical-laced water and sand, the controversial process commonly known as hydraulic fracturing. Much more common in California, however – and in Midway-Sunset especially – is the simpler procedure of liquefying viscous hydrocarbons with an underground shot of steam. As much as 40 percent of California's roughly 200 million barrels of crude each year begins in the ground as a substance with the consistency of peanut butter. The only way to lift it is to heat it until it flows like honey.



Steam is pumped underground to warm and loosen thick crude oil so it can flow to the surface. U.S. DEPARTMENT OF ENERGY

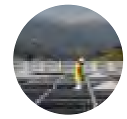
"California has a lot of low-quality oil resources," says Adam Brandt, a Stanford University engineering professor who was co-author of a recent article in the journal *Nature Climate Change* that focused on the intense climate impact of depleted oil fields. "We produce a lot of oil via steam generation, which consumes a lot of energy." Drillers commonly boil two to four barrels of water, he says, for every barrel of oil.

Steam has allowed the Midway-Sunset field to produce long beyond its predicted life and has helped make California the third largest producer of oil in the United States, behind Texas and North Dakota. But it also means that California – the state that stands at the forefront of climate leadership in the United States and that has pioneered renewable energy standards for utilities and a carbon-market for other polluters – also extracts, refines, and burns some of the dirtiest oil on the planet. Each steam-injected well in Midway-Sunset requires the burning of natural gas to produce the necessary steam and lift the oil, which in some cases comes up freighted with as much as 95 times as much water as crude. Then, at the refining stage, producers use more natural gas to transform heavy crude into gasoline. All of those factors combined make the oil from Midway-Sunset only one-and-a-half percent less carbon-intensive than tar sands oil from the Athabascan forests of Alberta.

So far, California's oil producers have done little to change the way they operate. That's partly because of scant pressure from state regulators, but also because California's steam-injected oil has not drawn the kind of attention, from either environmentalists or legislators, that hydraulic fracturing has, even though fracking is used in fewer than one-fifth of the state's wells. But many climate and energy experts say reforming California's dirty system of oil extraction is long overdue.

“It’s crazy for an environmentally conscious state to keep putting dirty fossil fuels into producing even dirtier fossil fuels.”

“It’s crazy for an environmentally conscious state to keep putting dirty fossil fuels into producing even dirtier fossil fuels,” says Deborah Gordon, director of the energy and climate program at the Carnegie Endowment for International Peace. “The state has got to start to break the chain somewhere.”



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In the face of a Trump environmental rollback, California stands in defiance. Read more.

One way to do that would be to start producing steam using the San Joaquin Valley’s plentiful and consistent supply of solar radiation. Concentrating solar thermal technology uses the sun’s energy to flash water to steam. In an electricity plant, that steam spins a turbine. At a steam-injected oil well, that steam could go straight into the ground. “If just 20 percent of the steam used in California fields was produced with solar,” says David Clegern, spokesman for the California Air Resources Board, “greenhouse gas emissions would be reduced by more than 3 million metric tons annually.” That’s equivalent to taking 643,000 cars off the road for a year.

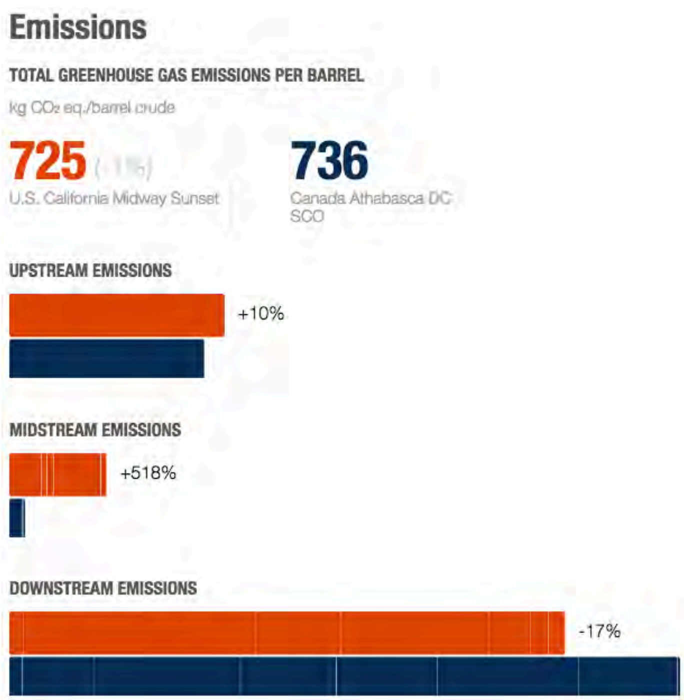
Another option for greening up oil operations would be to find alternative ways to create the hydrogen that necessarily gets added to heavy oil to make gasoline. “Hydrogen is a really big part of this,” Gordon says. Right now, refineries produce the hydrogen they need by “steam reforming” – pumping steam into methane, the primary component of natural gas. Refineries could instead produce hydrogen with electrolysis, Gordon says, separating hydrogen from oxygen in their own wastewater by subjecting it to an electrical current.

“Will it be cheap?” says Gordon. “No. Are electric vehicles cheap? We’re not talking cheap. We’re talking better and safer for a population that cares.”

Two years ago, Gordon and Jon Koomey, an energy researcher at Stanford University, partnered with Stanford’s Brandt and Joule Bergerson of the University of Calgary to create the Carnegie Endowment’s Oil-Climate Index. Using Brandt’s software tool, the Oil Production Greenhouse Gas Emissions Estimator, they ranked 30 oils worldwide based on the lifecycle emissions of greenhouse gases and other metrics.

Oil is described as heavy or light depending in part on its hydrogen-to-carbon ratio. It’s also ranked according to an American Petroleum Institute metric known as API gravity. Any oil with an API gravity of 22.3 degrees or less is considered heavy oil, richer in carbon than lighter oils. Volatile light crude from North Dakota’s Bakken Formation has an API gravity of 40 to 50 degrees; it contains so much hydrogen that you can pour it straight into a gas tank. Crude from California's South Belridge field, north of Midway-Sunset, has an average API gravity of 15 degrees.

Heavier oils not only contain more carbon to begin with, they need more energy to be extracted and refined. A barrel of light crude from the Eagle Ford formation in Texas (API gravity 50 degrees), for instance, emits 38 percent less carbon dioxide from well-to-gas tank than a barrel of bitumen from Alberta, and 37 percent less than heavy crude from Midway-Sunset.

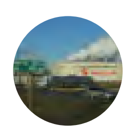


A comparison of greenhouse gas emissions produced per barrel of oil from California's Midway-Sunset field and the most carbon-intense type of oil from the Alberta tar sands. CARNEGIE ENDOWMENT FOR INTERNATIONAL PEACE / OIL-CLIMATE INDEX

California's dirty oil hasn't motivated the same resistance from environmental groups as has oil from Alberta's tar sands.

California's dirty oil hasn't motivated the same resistance from environmental groups as has oil from Alberta's tar sands. California refineries, with their decades of experience processing heavy crude, are uniquely suited to handle tar sands oil, and activists spent years blocking the import of Canada's oil to California's refineries. But environmentalists have not focused as much on California's own oil, says Anthony Swift, director of the Natural Resources Defense Council's Canada Project, because fields like Midway-Sunset are on the decline, while Canada's operations continue to expand. "Canadian companies are still greenlighting new fields," says Swift. "They expect those fields to continue into production until 2070 or 2080. That's completely inconsistent with any credible safe-climate scenario."

Other green groups say they are less interested in improving energy efficiency in oil-field operations than they are in shutting them down. "We don't support the use of concentrating solar power for oil production, because that production has to be phased out," says Shaye Wolf, the climate science director at the Center for Biological Diversity in Oakland, California. "We can better spend our resources on clean energy technologies that truly protect our climate and communities."



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Once unstoppable, Alberta's tar sands are battered from all sides. Read more.

Gordon, who in her long career as a chemical engineer has worked for both Chevron and the Union of Concerned Scientists, warns that such a petroleum-free future is a long way off. California likely has decades left of petroleum in the ground, and even if the world switched to solar-powered electric cars tomorrow, petroleum would still be used in plastics, drugs, and jet fuel. “We could be at this another 100 years,” she says, “and oil resources will only get harder to extract.”

The California Air Resources Board does include emissions from steam generation in evaluating oils for its low-carbon fuel standard, and regulators hold oil-field steam generators to stringent standards for traditional pollutants, such as nitrogen oxides and sulfur. But language governing greenhouse gas emissions from transportation fuels, which might have sparked innovation in the oil industry, was written out of a 2015 bill that set higher renewable energy standards for the state’s electric utilities. Carbon-credit prices remain too low for the state’s cap-and-trade program, which was recently extended through 2030, to motivate oil drillers to reduce climate-damaging emissions or limit their use of steam. In fact, the method has only gained popularity during the years of the carbon market’s existence.

Oil pumps in California's Midway-Sunset oil field. VERIFEX/FLICKR

“Between 2012 and 2015, the amount of steam injected in California oil fields increased by approximately 30 percent,” Clegern says. As long as natural gas prices stay low, “the production of heavy oil will continue in California with or without implementation of solar steam.”

Oil industry spokespeople would not comment about any plans to address the carbon footprint of the crude they draw up from their increasingly depleted wells, referring questions to the industry’s trade group, the Western States Petroleum Association. “The oil and gas industry is constantly testing new technologies to more effectively deliver affordable and reliable energy in the safest possible way,” the organization’s president, Catherine Reheis-Boyd, said in an emailed statement.

Chevron did, however, launch a solar-to-steam demonstration project at one of its San Joaquin Valley oil fields in 2011. The concentrating solar collector aimed 7,600 mirrors at a tower, where a boiler turned water to steam. Built by BrightSource Energy, Inc., of Oakland, it was dismantled in 2014. “The economics were not attractive compared to the current [gas-fired] process," a Chevron spokesperson told Natural Gas Intelligence, an industry publication.

Another company, Texas-based Cenergy, uses standard, run-of-the-mill solar panels to produce electricity at a Midway-Sunset site operated by Seneca Resources Corporation. The 3.1 megawatt-capacity plant doesn't directly produce steam, but it is expected to offset 20 percent of the electricity the company uses during its entire extraction process, contributing to the state's low-carbon fuel goals.

> A California company says its solar generator could reduce emissions associated with oil production by 80 percent.

But there may be new hope for solar-to-steam plants. GlassPoint, of Fremont, California, has successfully deployed another kind of concentrating solar thermal technology in the oil fields of Oman, in which troughs of mirrors are used to flash water to steam. According to the company, the solar generator has the potential to reduce emissions associated with oil production by 80 percent. A GlassPoint spokeswoman said the company is weeks away from announcing plans for a California installation.

Change comes slowly in the calcified and competitive petroleum industry, where shareholders' focus on profits outweigh climate concerns in the long term. Racheting up climate policies, says the NRDC's Swift, could exert more pressure on oil companies to refom their carbon-intensive practices while California transitions to a clean-energy future.

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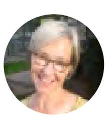
"There's not going to be a moment where fossil fuel production stops, and renewable energy begins," he says. "It's going to be a transition. An essential part of it is investing in electrical cars. But another part of it is cleaning up existing sources."



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COMMENTARY

In 2024, who will California voters believe more: Oil companies or Jane Fonda?

BY JIM NEWTON
DECEMBER 21, 2023

An active oil derrick near homes in the city of Signal Hill in Los Angeles County on Oct. 19, 2022. Photo by Pablo Unzueta for CalMatters

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When **Hiram Johnson** and the California Progressives adopted the referendum, ballot initiative and recall process just over a century ago, they had a fairly specific goal in mind. They sought to reserve power for the people in instances where big business, **specifically the Southern Pacific Railroad**, wielded corrupt influence.

The reforms were meant to allow the electorate to remove the officials responsible, pass laws over their objections, or undo their acts. People over business.

Yet next fall Californians will consider a referendum sponsored by big business to undo the act of the peoples' elected leaders – a recurring theme in recent years. The specific matter at issue is **Senate Bill 1137**, a 2022 law that bans oil drilling within 3,200 feet of homes, schools, hospitals and the like. **Oil companies responded by circulating petitions** to challenge the legislation with a referendum, and **voters will get the opportunity to decide its fate** next year.

"It's an egregious attack on democracy," actress and activist Jane Fonda (yes, *that* Jane Fonda) told me recently. "It's the most egregious attack on democracy and public health I've ever seen."

At its core, the referendum is one of "environmental justice," said Fonda, who is helping organize the opposition. In a state where some 2.7 million people live within a few thousand feet of an oil well, public health advocates made their case **that buffer zones were in the public interest**, and their elected leaders responded.

That is how representative democracy is supposed to work. The referendum seeks to undo that, and it does so by marshaling a tool historically intended to curb the power of big business.

There are certainly substantive issues to consider. How bad are the health consequences of growing up in a home a few hundred feet from an oil well? Would creating the setbacks required by the bill damage the economy of California or raise the price of gasoline? Would that price be worth paying if it was spent to protect the state's public health?

Supporters of the bill (and therefore, the opponents of the referendum) say that the price is minimal and the benefit considerable. A **report to the Los Angeles City Council** noted that "activities related to oil and gas operations have been associated with many potential negative health and safety impacts, especially when they occur in close proximity to sensitive uses such as homes, schools, places of worship, recreation areas, and healthcare facilities."

In 2022, the council voted to ban new wells and phase out old ones over the next two decades.

SB 1137 was a companion idea. But even as Gov. Gavin Newsom signed the bill, **oil companies rushed to head it off**, calling their effort "Stop the Energy Shutdown."

They were successful. After spending some $20 million to collect signatures, the law was shelved. Next November's vote will determine if it gets implemented.

The industry's argument is that, as long as oil is being consumed, it is better for it to come from local sources. If SB 1137 is allowed, California would be forced to "increase its reliance on imported oil, which could come from other oil-rich countries," Rock Zierman, CEO of the California Independent Petroleum Association, wrote in an **op-ed** for CalMatters.

Last week, Zierman elaborated on that point, asserting that the law does nothing to decrease the state's demand for oil.

"Californians consume 1.8 million barrels of oil a day," he noted.

Supporters of the law question the seriousness of that argument, pointing out that oil is an internationally traded commodity, and a few oil wells in California residential neighborhoods are a negligible piece of the global market. Darkly warning of increased gas prices in this context is scare politics.

For whatever reason – concern for prices, resistance to regulation, fear of the precedent of government mandates – oil companies have chosen to fight this. But they start at an obvious disadvantage: Californians have fought Big Oil before – some chart the modern environmental movement from the **1969 Santa Barbara oil spill**. Environmental justice, with its emphasis on the disparate effects on poor Californians, is a compelling political argument in this very blue state.

It would take a lot of money to persuade Californians to trust Big Oil with their health and safety. But if Big Oil is unpopular, **it is also rich**. The campaign over drilling setbacks could thus be both a threat to democracy and a test of it.

Which brings me back to Jane Fonda.

She is not an official campaign spokesperson, but Fonda brings near-iconic status to the effort. First introduced to the public decades ago as a beautiful and talented actress, Fonda has parlayed her fame into political action. She has placed her reputation – even her life – in defense of participatory democracy. It is natural, then, that this test of democratic institutions and environmental protection drew her interest.

Fonda's activism has made her a polarizing figure at times, but the issues that may have once struck mainstream America as fringe thunderbolts have gradually become recognized as sensible, even moderate, positions. It hardly seems radical today to have advocated for ending the Vietnam war, desegregation and equal voting rights; empowering women; or protecting the environment.

Fonda championed those causes when they were hard. In 2023, they seem natural.

"We've made quite a lot of progress," she told me. "But the problems haven't gone away."

The solution, she said, is to energetically plow ahead. In our interview, she quoted Greta Thunberg, the young climate change activist. Pursue action, Thunberg advised Fonda. "Hope will follow."

It is typical Fonda that this veteran of so many struggles, now in her 80s but as clear-eyed, open-hearted and forceful as ever, would credit a teenager for inspiration.

Over the coming months, Californians will get the chance to decide who to believe: oil companies and their spending or Fonda, her allies and her principles. I would not bet against Fonda.

LETTER • OPEN ACCESS

Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming

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Abstract

Methane mitigation is essential for addressing climate change, but the value of rapidly implementing available mitigation measures is not well understood. In this paper, we analyze the climate benefits of fast action to reduce methane emissions as compared to slower and delayed mitigation timelines. We find that the scale up and deployment of greatly underutilized but available mitigation measures will have significant near-term temperature benefits beyond that from slow or delayed action. Overall, strategies exist to cut global methane emissions from human activities in half within the next ten years and half of these strategies currently incur no net cost. Pursuing all mitigation measures now could slow the global-mean rate of near-term decadal warming by around 30%, avoid a quarter of a degree centigrade of additional global-mean warming by midcentury, and set ourselves on a path to avoid more than half a degree centigrade by end of century. On the other hand, slow implementation of these measures may result in an additional tenth of a degree of global-mean warming by midcentury and 5% faster warming rate (relative to fast action), and waiting to pursue these measures until midcentury may result in an additional two tenths of a degree centigrade by midcentury and 15% faster warming rate (relative to fast action). Slow or delayed methane action is viewed by many as reasonable given that current and on-the-horizon climate policies heavily emphasize actions that benefit the climate in the long-term, such as decarbonization and reaching net-zero emissions, whereas methane emitted over the next couple of decades will play a limited role in long-term warming. However, given that fast methane action

can considerably limit climate damages in the near-term, it is urgent to scale up efforts and take advantage of this achievable and affordable opportunity as we simultaneously reduce carbon dioxide emissions.

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Supplementary data

1. Introduction

Methane is a major contributor to climate change and plays a dominating role in how fast the climate warms (Myhre *et al* 2013). However, although myriad mitigation strategies have been identified over the last decade (e.g. EPA 2013), uptake remains slow and global emissions continue to rise (Saunois *et al* 2020). Given that climate policies are mostly oriented around long-term climate stability goals (IPCC 2018) and use climate metrics that undervalue methane's role in the near-term (Ocko *et al* 2017), there is less urgency to reduce methane now at the extent warranted. Here we demonstrate the value of fast action to deploy readily available methane mitigation measures as opposed to slow and delayed action, with a key focus on sectoral roles. We have a powerful opportunity to slow down the rate of warming and limit temperature rise by midcentury if we act now, which would provide considerable benefits to society and ecosystems.

The prominent and growing role of methane emissions in present and future climate change is increasingly understood—methane contributes to at least a quarter of today's gross warming (Myhre *et al* 2013, Ocko *et al* 2018), its concentration continues to rise rapidly in large part from anthropogenic sources (Schwietzke *et al* 2016, Fletcher and Schaefer 2019, Nisbet *et al* 2019, Hmiel *et al* 2020, Jackson *et al* 2020, Saunois *et al* 2020), and several studies have shown the outsized value of its mitigation in limiting warming over the next few decades due to its short atmospheric lifetime (Shindell *et al* 2012, Shoemaker *et al* 2013, Collins *et al* 2018, Smith *et al* 2020). These insights have led to the development of innovative technologies and strategies to reduce methane emissions from all major emitting sectors—such as the straightforward plugging of natural gas leaks (IEA 2017) to ruminant feed supplements (Hristov *et al* 2015)—and the resulting abatement potentials for readily available measures have been characterized (EPA 2013, 2019, IEA 2017, Harmsen *et al* 2019, 2020, Höglund-Isaksson *et al* 2020, Arndt *et al* 2021).

Given methane's short-lived presence in the atmosphere, deployment of these mitigation measures would have a near-immediate impact on slowing down the rate of warming. However, current government and company climate policies are focused on addressing long-term climate stability in particular (such as via net zero targets), which inadvertently imply that methane mitigation can wait until midcentury due to its short lifetime (IPCC 2018). Further, these policies use the traditional climate metrics Global Warming Potential and its Carbon Dioxide Equivalence counterpart, with a 100 year time horizon that undervalues the role of short-lived climate pollutants—such as methane—in driving near-term and rate of warming (Ocko *et al* 2017). While there is vast scientific consensus that severely limiting total global warming over the next century is essential to preventing profound damages to life on Earth, many risks to society and ecosystems arise from the rate of warming, and the ability to adapt to anticipated changes is greatly diminished by a quicker pace (IPCC 2018).

Therefore, while it is essential to minimize warming over the coming decades in addition to the long-term, we are currently on a path that supports either slow or delayed action on methane despite numerous readily available and affordable mitigation measures for each major-emitting sector (e.g. Höglund-Isaksson *et al* 2020). It is therefore possible that we are situated to miss an unmatched opportunity to slow down the rate of warming and its concomitant damages immediately (McKenna *et al* 2021).

Several studies to date analyze the climate benefits of methane mitigation (Shindell *et al* 2012, Hu *et al* 2013, Shoemaker *et al* 2013, Rogelj *et al* 2015, Stohl *et al* 2015, Collins *et al* 2018, Harmsen *et al* 2020, Lund *et al* 2020, Smith *et al* 2020). These studies cover a range of mitigation assumptions and timelines; employ different methodologies for determining climate impacts (from simple metrics to reduced complexity models to earth system models); contain varying scopes of temporal, spatial, and sectoral breakdowns; and assess different climate impact variables (mostly radiative forcing and temperature but also precipitation and sea level rise). Studies find that mitigation of methane can slow down the rate of warming and sea level rise (e.g. Hu *et al* 2013, Shoemaker *et al* 2013), lower midcentury warming (e.g. Shindell *et al* 2012, Smith *et al* 2020), and is essential to achieving long-term temperature targets (e.g. Collins *et al* 2018, IPCC 2018). Studies also show that direct methane mitigation measures are more effective at reducing emissions than reductions as a result of ambitious carbon dioxide mitigation (Harmsen *et al* 2020), and that stringent methane mitigation can allow for higher carbon dioxide budgets for a specific temperature target (Rogelj *et al* 2015).

Despite the range of methane mitigation timelines and magnitudes analyzed in previous studies, the benefits of rapidly deploying available mitigation measures compared to gradual or delayed actions remain unclear. Here, we synthesize the latest assessments on readily available oportunities to reduce methane emissions from agriculture, energy systems, and waste management, and evaluate the climate benefits of their deployment over different timelines by using a well-known reduced-complexity climate model. We divide methane mitigation measures into two categories: those that can be pursued now at no net cost even in the absence of carbon pricing (herein referred to as 'economically feasible' actions), and those that can be pursued now based on all existing technologies and strategies (herein referred to as 'technically feasible' actions). We evaluate the climate benefits over all timescales—both in the near- and long-term—for three implementation timelines: fast, slow, and delayed action. We present our results for aggregate methane emissions and also by individual sector, to show how sector-based mitigation contributes to the climate benefits.

By connecting existing sector-specific methane abatement measures to tangible near-term temperature benefits, we aim to mobilize the political and corporate will to accelerate and scale up deployment of these already available but greatly underutilized mitigation opportunities, and as a result, reduce climate damages well before midcentury. We emphasize that methane mitigation is not intended to replace the unequivocal need to urgently act to reduce carbon dioxide emissions, but rather is a complementary approach that can add critical near-term benefits not otherwise achievable.

▲ 2. Methods

2.1. Emissions scenarios

We develop three sets of future methane emissions: a baseline scenario representing no further climate action, and two scenarios for methane mitigation that represent a range of potential ambition from minimum to maximum action based on current cost assessments and available technologies. We consider three implementation timelines for both sets of mitigation scenarios: one with fast action beginning in 2020 with full deployment by 2030; one with slow action beginning in 2020 with full deployment by 2050; and one with delayed action beginning in 2040 with full deployment by 2050.

2.1.1. Baseline projections

Several previous assessments have developed global methane emissions projections for future baseline scenarios (e.g. Riahi *et al* 2007, 2017, JRC 2019, 2020, Harmsen *et al* 2019, 2020, EPA 2019, Höglund-Isaksson *et al* 2020). There is a widespread range of socioeconomic and technological assumptions embedded in these projections, as well as different regional, sectoral, and temporal coverage. Emissions range from 332 to 439 million metric tonnes (MMt) in 2020, 398 to 677 MMt in 2050, and 460 to 888 MMt in 2100.

For this analysis, we use the baseline methane emissions scenario developed by Höglund-Isaksson *et al* (2020). This is because of the availability of sector and subsector information, incorporation of the latest science and data (such as oil and gas estimates), and emissions that are in the middle of the range of available projections (2020: 351 MMt and 2050: 447 MMt). Höglund-Isaksson *et al* (2020) uses the integrated assessment modelling framework, GAINSv4, to estimate methane emissions through 2050 with a bottom-up sectoral approach informed by numerous resources. Baseline emissions consider effects from regulations and legislation adopted as of December 2018, with no further climate action beyond these measures. Extrapolation of baseline emissions trends through 2100 provides reasonable estimates when compared to other baseline scenarios that have projections throughout the end of the century (i.e. Riahi *et al* 2007, 2017, JRC

2019, Climate Watch 2021), and yields a total amount of 611 MMt of methane emitted in 2100. See supplemental material for data and comparisons with other assessments for total emissions and by sector (figure S1 (available online at stacks.iop.org/ERL/16/054042/mmedia)).

For baseline emissions of non-methane climate forcers, which are particularly important for analysing changes in the rate of warming, we use the most commonly employed RCP8.5 scenario. While some have argued that this is an unrealistic baseline (e.g. Hausfather and Peters 2020), others assert that RCP8.5 is particularly well-suited for emissions out to midcentury and not unreasonable for late century (Schwalm *et al* 2020). Given that this work is focused on the midcentury timeline and that the majority of our analysis is for methane impacts only (of which the magnitude of methane baseline or avoided warming is insensitive to the selection of a non-methane baseline—see supplemental material for more details), RCP8.5 is suitable for our purposes.

2.1.2. Abatement potentials

We consider two levels of methane mitigation that encompass a range of realistic methane actions. As a lower bound, we consider only actions that can be achieved at no net cost, without a price on carbon or methane; for actions that capture methane, the value of the captured methane is included in the cost assessment. The only exception is the inclusion of commitments made by oil and gas companies, which we consider as cost-effective in that companies have determined that these measures fit within their business models in the existing economic framework. We refer to this lower bound mitigation case as 'economically feasible.' As an upper bound, we consider the other end of the spectrum: the most optimistic case conceivable for methane abatement within the next ten years given existing technologies, practices, and structural changes that are either readily available for deployment or require at most minor improvements. However, we do not include consideration of more radical policy proposals (such as phase-out of methane pipelines or combustion) and changes in dietary behaviour (such as global veganism) as the achievability of these measures is much less realistic than implementation of technological strategies. We refer to this upper bound mitigation case as 'technically feasible,' and it inherently includes the economically feasible actions as well.

We surveyed the literature to identify economically and technically feasible abatement potentials for the six major emitting sectors that represent 90% of current emissions (livestock, rice production, the oil and gas supply chain, coal mining, landfills, and wastewater treatment; figure 1). Given that the relative abatement potentials of specific mitigation measures within each sector (such as an individual technology or action) will depend on a range of scientific and non-scientific characteristics that are regionally dependent (Höglund-Isaksson *et al* 2020), we restrict our analysis to assessing the relative climate benefits of total potential methane mitigation from each major sector. However, we include a list of the most prominent mitigation measures within each sector that are considered in the literature (table 1) and discuss in more detail in the supplemental material.

Figure 1. Global annual anthropogenic methane emissions abatement potentials in 2030 relative to baseline. Mitigation potentials are divided into two categories: economically feasible actions (no net cost based current cost assessments) and technically feasible actions (all available technologies); technically feasible includes economically feasible. Implementation of measures begin in 2020 with full deployment achieved by 2030. Sector percentages on the verge of the pie refer to share of total sector baseline emissions in 2030 assuming no further climate action. Sector percentages within the pie refer to economically and technically feasible abatement potentials as a percent below the baseline. In addition to no net cost options, we consider commitments made by oil and gas companies as 'economically feasible,' with the assumption that companies have found it fits into their business models. The contribution of company commitments to abatement potentials is shown in the line pattern. Note that more radical policy proposals or behavioural changes are not included here, which could increase mitigation levels. For example, human dietary changes could considerably reduce methane emissions from livestock at no cost. More information on data sources, assumptions, and explanations can be found in the supplemental material.

Table 1. List of prominent methane mitigation measures for each sector that are specified in at least one assessment of marginal abatement cost curves and maximum technical abatement potentials.

	Example mitigation measures considered in abatement potentials (* indicates sometimes can be at no net cost)
Livestock	Methane inhibitors*, electron sinks*, oils and oilseeds*, intensive grazing*, improved feed conversion*, manure coverage and digester systems*, selective breeding; do not include changing human diet
Rice	Improved irrigation systems*, cropping techniques*, and fertilization levels* such as incorporation of rice straw compost before transplanting coupled with intermittent irrigation and use of alternative hybrids and soil amendment
Oil & Gas	Upstream leak detection and replacement*, replacing pumps*, replacing with instrument air systems*, vapour recovery units*, blowdown capture*, replace with electric motor, early replacement of devices, replace compressor seal or rod, install flares, install plunger, downstream leak detection and replacement
Coal mining	Pre-mining degasification*, coal drying*, flooding abandoned mines*, ventilation air methane oxidation with improved ventilation, open flaring,
Landfills	Electricity generation with reciprocating engine/gas turbine/CHP/microturbine and landfill gas recovery for direct use*, source separation with recycling or treatment with energy recovery for municipal, recycling or treatment with energy recovery for industrial; no landfills of organic waste
Wastewater	Open sewer to aerobic wastewater treatment plan*, domestic wastewater treatment is upgraded from primary treatment to secondary/tertiary anaerobic treatment with biogas recovery and utilization, industrial wastewater treatment is upgraded to two-stage treatment such as anaerobic with biogas recovery followed by aerobic treatment

For abatement potentials at no cost ('economically feasible'), we use marginal abatement cost curve assessments developed by four sources: IEA (2017), EPA (2019), Harmsen *et al* (2019), and Höglund-Isaksson *et al* (2020). Given that Harmsen *et al* (2019) includes advancements in technology over time, we only use their estimates of abatement potentials for 2020 emissions, whereas we use 2030 estimates for EPA (2019) and Höglund-Isaksson *et al* (2020).

Abatement potentials at no cost are averaged across EPA (2019), Harmsen *et al* (2019), and Höglund-Isaksson *et al* (2020) for rice (6%), coal mining (6%), landfills (16%), and wastewater (1%) (% represents how much can be abated below 2030 baseline). For livestock (2%), we average EPA (2019) and Höglund-Isaksson *et al* (2020) estimates given that these values are more conservative than the Harmsen *et al* (2019) outlier value of 22%. For oil and gas emissions, we supplement IEA (2017) no cost abatement potential of 45% below present-day emissions with oil and gas company commitments of limiting upstream natural gas leaks to 0.2% of total production levels. This yields an increase in the abatement potential from 50% below 2030 levels to 77%. More details regarding this calculation and its feasibility are provided in the supplemental material. Further, locked in capital makes several measures more expensive today than they may become in the future, and therefore we expect that several measures will become more cost effective over time. In addition, as the price of oil and gas fluctuates, the amount of emissions that can be reduced for no net cost from oil and gas measures will also fluctuate. We do not include changing cost effectiveness over time in our analysis.

For abatement potentials that cover all existing technological mitigation measures at any cost ('technically feasible'), we survey the scientific literature in addition to the above sources. We apply the most optimistic abatement potentials by sector to global emissions, therefore representing a best-case scenario of potential reductions with all-in methane action. However, we note that there is large diversity in systems and practices across world regions and thus applying optimistic abatement potentials on a global scale has uncertainties. Further, we do not include political, social, and information barriers to implementing available technologies, that undoubtedly exist in many parts of the world. The reason for this approach is to provide information on the maximum climate benefits achievable from deployment of readily available measures.

For the livestock sector, we apply the upper end abatement potentials from a meta-analysis on methane mitigation strategies for livestock (30% below baseline; Arndt *et al* 2021). We use estimates from Höglund-Isaksson *et al* (2020) for rice (49%), coal mining (61%), landfills (80%), and wastewater (72%). While these potentials are identified for 2050, they do not reflect any major developments in technology beyond today, and for our upper end 'technically feasible' estimates, we do not consider the role of locked in capital. For oil and gas, we supplement the IEA (2017) abatement potential of 75% below current levels with voluntary company commitments of capping upstream leakage. This results in an 83% below 2030 level abatement potential rather than 77% without industry targets.

Overall, while the existing potential to reduce methane emissions varies considerably by sector and by mitigation level (figure 1), if deployed in parallel they can cut anticipated methane emissions in 2030 in half, with a quarter of total emissions reduced at no net cost.

2.1.3. Mitigation timelines

Abatement potentials are applied to baseline emissions throughout the century to develop two sets of methane mitigation scenarios: economically feasible and technically feasible paths. For each of these scenarios, we develop three implementation timelines that vary mitigation deployment between 2020 and 2050. After 2050, both sets of mitigation scenarios are identical amongst the three timelines.

To capture the climate benefits of an immediate effort to deploy available methane mitigation measures, we assume an early and rapid implementation plan with deployment beginning now and reaching maximum abatement potentials in 2030. This leads to an immediate drop in emissions from 2020 to 2030. However, because the majority of abatement potentials are defined as a reduction potential below a baseline, as populations grow and countries develop, emissions will continue to slowly rise even with sustained mitigation efforts. This is because demand for livestock, for example, will increase in the future, yet we hold the abatement potential (percent below baseline) constant throughout the end of the century (i.e. no further mitigation potential is tapped after 2030).

To compare the benefits to slower and delayed implementation plans, we also analyse implementation beginning in 2020 with linear ramp up reaching full potential by 2050 ('slow' mitigation), and implementation beginning in 2040 and reaching full potential by 2050 ('delayed' mitigation consistent with what is needed to achieve long-term temperature targets).

We compare our mitigation scenarios with existing literature in the supplemental material (figure S2). Overall, our pathways fall within the realm of previously developed scenarios. Comparing our technically feasible fast action scenario in particular shows that it is most similar to methane emissions developed by JRC GECO (2019, 2020) for paths consistent with 1.5 °C temperature targets, as well as a short-lived climate pollutant mitigation path developed using ECLIPSE (Stohl *et al* 2015). In the long-run, given that we keep mitigation levels at the same abatement potentials for each sector (and do not account for new technologies, etc), we find that our economically feasible scenarios lead to emissions that are higher in 2100 than all but one scenario (SSP4-60). Our technically feasible scenarios lead to emissions in 2100 that are in the middle of the range. Overall, most existing methane mitigation scenarios are characterized as having slow implementation of mitigation measures in the near-term.

2.2. Climate model

We employ a prominent and freely available reduced-complexity climate model, Model for the Assessment of Greenhouse-gas Induced Climate Change (MAGICC) version 6 (Meinshausen *et al* 2011), which has been used in several policy-oriented climate analyses involving short-lived climate pollutants (e.g. Shoemaker *et al* 2013, IEA 2017, Reisinger and Clark 2018, Smith *et al* 2020). MAGICC's ability to simulate temperature responses to methane emissions has been previously validated with a higher complexity climate model; Ocko *et al* (2018) performed a series of experiments to compare forcing and temperature responses to historical methane emissions in MAGICC to those from a more complex coupled global chemistry–climate model, GFDL-CM3. Overall forcings and temperature responses were comparable between the two models for both direct and indirect methane effects. Further confidence in MAGICC comes from decades of work improving model parameterizations (Meinshausen *et al* 2011) and comparisons of its performance within the context of other reduced complexity climate models (Nicholls *et al* 2020).

The major benefits of using a reduced-complexity climate model are ease of use with basic knowledge and limited computational infrastructure; rapid results for time-sensitive policy purposes; and the ability to analyse small forcing changes due to the absence of unforced internal variability. However, limitations exist, such as coarse spatial resolutions and parametrizations, and one common to all climate models, uncertainties based on the extent of our physical understanding of myriad systems.

MAGICC represents the coupled carbon-cycle climate system as a hemispherically averaged upwelling-diffusion ocean coupled to a four-box atmosphere and a globally averaged carbon cycle model (Meinshausen *et al* 2011). We use default model properties and inputs, but update methane-related properties based on the latest science; detailed information on model components, inputs, and parameters, as well as modifications for this analysis, can be found in the supplemental material. We run 50 distinct 335 year integrations from 1765 to 2100. For 11 integrations, we include a 190-member ensemble based on simulations run using different sets of atmospheric, oceanic, and carbon cycle parameters derived from 19 atmosphere-ocean global climate models and 10 carbon cycle models (Meinshausen *et al* 2011); equilibrium climate sensitivity (ECS) in the ensemble ranges from 1.9 °C to 5.73 °C, with a mean (median) of 2.88 °C (2.59 °C). In the default model properties, the ECS is 3 °C, and therefore single-run simulations have slightly higher temperature responses than ensemble means. A full list of experiments can be found in the supplemental material, and include baseline scenarios, mitigation pathways by sector and in parallel, as well as sensitivity tests and uncertainty assessments (such as how uncertainties in methane parameters including lifetime and oxidation effects impact our results). Unless otherwise noted, all uncertainty ranges reported herein refer to ±one standard deviation from the mean based on the 190-member ensemble.

3. Results

We analyze the anticipated temperature responses to baseline methane emissions in the absence of further climate action, and assess the benefits of implementation of available mitigation measures that could prevent a large fraction of methane from being emitted over different timelines. In the baseline case, methane emissions from human activities are expected to continue rising over the next few decades and throughout this century, yielding a potential increase in emissions by end of century of more than 70% relative to current levels, with emissions exceeding 600 MMt per year by 2100 compared to today's level around 375 MMt yr^{-1}. Three quarters of emissions are projected to come from the livestock, oil and gas, and landfill sectors—with similar emissions magnitudes projected for each.

Historical methane emissions contribute to around 0.5 °C (±0.1 °C) of present-day global-mean warming above preindustrial levels (1850–1900; figure 2), which is around half of carbon dioxide's contribution (0.9 ± 0.2 °C) and a quarter of the gross warming from all warming pollutants (1.85 ± 0.4 °C); note that cooling climate pollutants mask some of this warming in the net absolute global-mean temperature. With the expected rise in methane emissions over the next few decades, methane may contribute 0.6 °C (±0.1 °C) by 2050, which would account for more than 20% of the warming from all warming pollutants if non-methane forcers followed an RCP8.5 trajectory. By end of century, methane emissions in the absence of further climate action could contribute to around 0.9 °C (±0.2 °C) of global-mean warming (figure 2). We note that this temperature response is insensitive to the non-methane baseline emissions assumptions (see supplemental material). Given that several methane baseline projections in the literature suggest even larger future methane emissions in the absence of further climate action, this level of warming could be even higher.

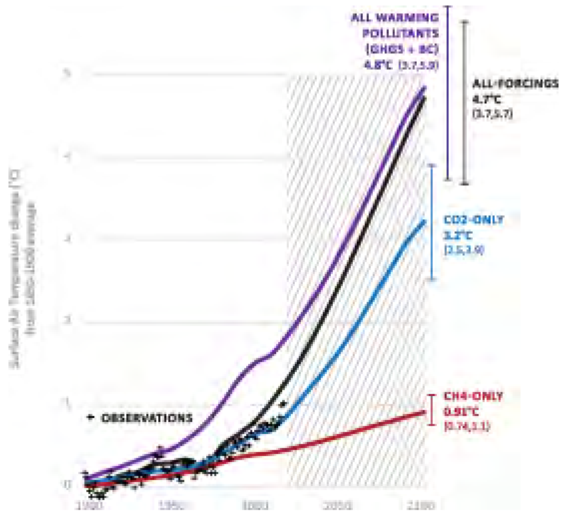

Figure 2. Global-mean surface air temperature change (°C relative to the 1850–1900 global-mean average) in response to historical and future (baseline) anthropogenic methane emissions, compared to temperature responses from all anthropogenic and natural forcings, all anthropogenic warming pollutant emissions (greenhouse gases and black carbon), and anthropogenic carbon dioxide emissions - for 'no further climate action' scenarios. Error bars show ±one standard deviation from the ensemble-mean based on a 190-member ensemble developed by combinations of climate and carbon cycle parameters based on 19 AOGCMs and 10 carbon cycle models, respectively. Future emissions of all non-methane climate pollutants are from RCP 8.5, and the methane-only temperature responses is insensitive to the non-methane climate pollutant emission scenario. Observations of temperature changes to date relative to 1880 global temperatures are shown in +markers and are taken from NOAA (2020) data.

However, a survey of the literature suggests that rapid deployment of available abatement technologies and strategies by sector could cut anticipated global methane emissions in 2030 by 57% (figures 1 and 3(a)). Further, we could achieve a reduction of 24% below anticipated levels in 2030 through deployment of cost effective measures alone (figures 1 and 3(a)). Given methane's strong radiative efficiency yet short atmospheric lifetime (Myhre *et al* 2013), these actions to reduce methane emissions will have near-immediate effects in lowering global-mean temperatures.

Figure 3. Global anthropogenic methane emissions and resulting temperature responses from 2020 through 2100 for baseline and mitigation scenarios. (a) Emissions for baseline (red) and mitigation (blue) scenarios for three implementation timelines: fast mitigation (solid blue lines), slow mitigation (dashed lines), and delayed mitigation (dotted lines). (b) Global-mean temperature responses (°C) attributed to future global anthropogenic methane emissions only based on a 190-member ensemble. (c) Near-term temperature benefits of mitigation actions in terms of avoided warming (°C) in 2050 and reduction in 2030–2050 decadal warming rate (%) relative to the all-forcing baseline scenario. Error bars represent ±one standard deviation from the ensemble-mean based on a 190-member ensemble.

We find that relative to global-mean average warming rates around 0.4 °C per decade from 2030 to 2050 in the absence of further climate action, fast action to pursue all economically feasible measures by 2030 could slow this rate of warming by 12% (±1%), and this benefit could double to 26% (24,30) with deployment of all technically feasible measures (figure 3(c)). This slower pace of global-mean warming means over a tenth of a degree (°C; ±0.01) may be avoided by midcentury from economically feasible actions with over a quarter of degree (°C; ±0.04) avoided from technically feasible mitigation measures (figures 3(b)–(c)).

However, many of these near-term benefits are missed if methane action is slow or delayed. For example, we could lose the opportunity to avoid an additional 0.2 °C of global-mean warming in 2050 if we delay methane mitigation until 2040 (figures 3(b)–(c)) and lose the chance to slow global-mean warming by nearly an additional 20%; this is an entirely feasible path given the current focus on net zero commitments for a 2050 timeframe. The rate of implementation also matters, because we miss some benefits even if we act early, but slowly. Beginning actions now but with full implementation only achieved by 2050, could yield 0.07 °C additional global-mean warming by 2050 and a greater than 5% increase in global-mean warming rate from 2030 to 2050 compared to early and rapid mitigation (figures 3(b)–(c)).

In the long-term, we find that sustaining economically feasible mitigation measures throughout the 21st century could avoid additional global-mean warming by nearly a quarter of a degree (°C; ±0.05) by 2100, whereas pursuing all technically feasible measures could avoid half a degree (°C;

±0.09) (figure 3(b)). This level of avoided warming is crucial for staying below the widely agreed upon global-mean temperature target of 2 °C above preindustrial levels.

While the different mitigation implementation timelines continue to play a role after 2050 in determining overall magnitudes and rates of global-mean warming from methane—even though the emissions pathways are identical post-2050 (figures 3(a) and (b))—the differences become smaller over time and generally merge by 2100. Therefore, if climate policy continues to focus on long-term time horizons, the powerful near-term climate benefits of fast methane action relative to slow or delayed action can be overlooked given that long-term impacts are similar for all timelines. This would miss a major opportunity to limit warming and its damages over the next few decades. We note that the magnitudes of avoided global-mean warming reported herein are insensitive to the non-methane baseline emissions assumptions, however, the relative reductions in the global-mean rate of warming would increase if non-methane baseline emissions decrease (see supplemental material for more information).

The relative roles of major sectors in contributing to the near- and long-term climate benefits from fast methane action vary considerably by sector (figure 4). The majority of economically feasible actions come from the oil and gas sector, accounting for around 80% of the avoided warming from economically feasible methane mitigation actions over all timescales (figure 4); 20% of this avoided warming comes from agreed upon targets by top oil and gas companies to reduce upstream leakage (OGCI 2018). We find that implementing current net zero cost oil and gas supply chain mitigation measures, such as leak detection and repair programs, along with fulfilment of company commitments of capped leakage rates, could avoid around 0.1 °C of global-mean warming by midcentury and 0.2 °C by end of century relative to a no further action baseline that suggests the oil and gas sector could contribute 0.15 °C to warming by 2050 and 0.25 °C by 2100 (figure 4).

Figure 4. Baseline temperature responses and avoided warming in °C by sector for methane mitigation measures fully employed by 2030 and maintained throughout the 21st century, for both economically and technically feasible measures. Economically feasible measures ('econ') refer to current no net cost options. For oil and gas, we include commitments made by oil and gas companies, with the assumption that companies have found it fits into their business models. The contribution of company commitments to avoided warming beyond current no net cost options is shown in the line pattern ('econ

cc'). Technically feasible measures include all readily available technologies in addition to no net cost options. Note that the sum of sector totals are slightly than those in figure 3(b), which is mainly due to a higher ECS used in single model runs (3 °C) compared to the 190-member ensemble means (2.88 °C).

For technically feasible mitigation, abatement measures for landfills and livestock play important roles in addition to oil and gas (figure 4). Implementation of all available landfill measures (requiring at most only minor improvements)—such as source separation—could avoid 0.16 °C of global-mean warming in 2100 relative to a no further action baseline (figure 4). Deploying all livestock abatement strategies—such as methane inhibitors and improved manure management—could avoid nearly 0.1 °C of global-mean warming in 2100 relative to a no further action baseline (figure 4). However, given the amount of livestock emissions that currently cannot be addressed with existing technologies, residual methane emissions from livestock are expected to contribute to half of the remaining future methane emissions unless there are behavioral changes and technological advancements.

Given that there are specific uncertainties associated with methane's climate impacts in addition to the various uncertainties associated with all models and emissions estimates, we perform several sensitivity tests to assess how methane-related model parameters affect our results. For example, there are uncertainties associated with the radiative effects from methane's oxidation processes and methane's atmospheric lifetime. Overall, the consideration of their individual uncertainties in our analysis suggests a global-mean temperature rise by end of century from baseline methane emissions that ranges from 0.75 °C to 1.5 °C; see supplementary material for more details. Further, we note that accounting for positive climate feedbacks such as melting tundra may lead to even more warming from methane emissions and is currently not included in our model.

4. Conclusions

The goal of this study is to assess the value of rapidly deploying available methane mitigation measures as compared to slower implementation timelines or delayed action, with an emphasis on sectoral contributions to climate benefits over all timescales. We find that while the potential to reduce methane emissions with existing mitigation measures varies considerably by sector, if deployed in parallel can cut expected 2030 methane emissions in half, with a quarter at no net cost. We find that full deployment of these available mitigation measures by 2030 can slow the rate of global-mean warming over the next few decades by more than 25%, while preventing around a quarter degree (°C) of additional global-mean warming in 2050 and half a degree (°C) in 2100. On the other hand, slow or delayed methane action leads to a 5% or nearly 20% increase in global-mean warming rate from 2030 to 2050 relative to fast action, respectively. Oil and gas measures dominate the avoided warming from economically feasible actions, and landfill measures play a secondary role to oil and gas in the avoided warming from technically feasible actions. Livestock measures also play an important role for technically feasible methane mitigation, but a considerable fraction of emissions from livestock still remain unabated.

Our results are in agreement with previous studies that show sizable near-term and long-term climate benefits from stringent methane mitigation, with similar levels of avoided warming in midcentury and end of century given the range in assumptions and methods (Shindell *et al* 2012, Shoemaker *et al* 2013, Stohl *et al* 2015, Rogelj *et al* 2015, Reisinger and Clark 2018, Collins *et al* 2018, Harmsen *et al* 2020, Smith *et al* 2020). Our analysis adds to this growing body of literature by assessing the role of different mitigation timelines in affecting the near-term climate benefits, and by showing the sectoral contributions over time. This study illuminates the near-term value of fast methane action as opposed to slower or delayed action.

In the long-term, the large potential in avoided warming from technically feasible measures is similar in magnitude to the upper end of projections of avoided global-mean warming from phasing out another important short-lived climate pollutant, hydrofluorocarbons (HFCs; Xu *et al* 2013). The potential avoided warming from HFC phase-out sparked an international agreement to curb future emissions growth—the Kigali Amendment to the Montreal Protocol—which entered into force in January 2019. Methane mitigation has even larger potential benefits than HFC mitigation because its future impact is projected to be double that of HFCs (figure 3(b)).

The long-term climate benefits from both economically and technically feasible methane mitigation scenarios in this analysis can also be considered underestimates given that we expect more abatement actions to become cost effective with technology turnovers, and more abatement actions to become available with technological advancements; neither of which are considered in our mitigation pathways. For example, the discovery, development, and scale up of emerging techniques could lead to higher sectoral abatement potentials, such as genetic selection for low-methane emitting phenotype (de Haas *et al* 2017). Methane emissions can be further reduced by shifts in behaviors such as decreased consumption of cattle products and reduced food waste. Proposals to remove methane from the atmosphere could also come to fruition (Jackson *et al* 2019). In addition, as more economies put a price on carbon or consider other forms of payment to account for methane damages (via ozone) to public health, agriculture, forests, etc (Shindell *et al* 2012, 2017), the cost effective options will expand, and the economically feasible potential would move closer to the technically feasible potential.

While we do not expect the methane mitigation measures we consider in our analysis to significantly affect emissions of other major climate pollutants, it is possible that some mitigation strategies for rice paddies can increase nitrous oxide emissions—although techniques exist to prevent this from occurring (Kritee *et al* 2018). On the other hand, actions designed to address other climate pollutant emissions, mainly carbon dioxide, can simultaneously reduce methane emissions from the energy sector. However, studies show that direct methane mitigation measures play a larger role in reducing methane compared to indirect methane reductions (Harmsen *et al* 2020), and provide important, additional climate benefits (IEA 2017). Further, many decarbonization pathways suggest that methane emissions will not be considerably reduced before midcentury (Riahi *et al* 2017) given that many strategies include an initial phase of switching from coal to natural gas, or, deployment of carbon capture and storage technologies—both of which will not appreciably reduce methane emissions. Therefore, we do not expect decarbonization of energy systems to affect the majority of our near-term climate benefits from direct methane mitigation measures.

Overall, the ability to substantially mitigate methane emissions with existing strategies is clearly an effective lever to limit future warming and associated damage to social and natural systems. Through immediate and rapid implementation of available methane mitigation measures, many that incur no net cost, we could see significant benefits in a single generation through slowed rates of warming, while also setting ourselves on a better course for generations to come. Employing these measures is undoubtedly essential to achieving ambitious warming targets, and can reduce the likelihood of passing tipping points and triggering positive feedbacks (Collins *et al* 2018, Fu *et al* 2020). Further, methane mitigation has been shown to be of additional benefit through reductions in tropospheric ozone that is toxic to many crops (Shindell *et al* 2012). While not a substitute for the unequivocally-imperative need of reaching carbon dioxide neutrality, methane mitigation is a powerful ally that should be pursued now with increased seriousness.

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Data availability statement

All data that support the findings of this study are included within the article (and any supplementary files).

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Oil Giants Pump Their Way to Bumper Profits

Exxon, Chevron and Shell reported robust earnings and large payouts to investors as they continued to expand their fossil-fuel production.

By Stanley Reed

Published Feb. 2, 2024 Updated Feb. 3, 2024

Exxon Mobil and Chevron, the largest U.S. energy companies, on Friday reported sizable profits for the final quarter of last year, showing that the oil and gas industry remained robust at a time of doubts because of climate change concerns.

The companies' earnings were down from the bonanza year of 2022, when a surge in prices pushed up profits, but were otherwise the strongest in recent history.

Exxon earned $7.6 billion in the fourth quarter of 2023, a 40 percent fall from a year earlier. For all of 2023, the company reported $36 billion in earnings, compared with $55.7 billion in 2022. Before that, the last time Exxon made more than $30 billion in a year was in 2014.

Chevron reported earnings of $2.3 billion in the fourth quarter, down from $6.3 billion a year earlier. The change was due to lower commodity prices and write-downs, especially in the company's home state, California. For the year, the company made $21.4 billion, down from $35.4 billion in 2022 but, like Exxon, otherwise its biggest annual profit in a decade.

The companies generated enough cash to fund big dividends and share buybacks. Such payouts are what investors now look for in the industry, analysts say.

"In 2023, we returned more cash to shareholders and produced more oil and natural gas than any year in the company's history," Mike Wirth, Chevron's chief executive, said in a statement. The company said it bought back 5 percent of its outstanding shares during the year.

Exxon paid out $14.9 billion in dividends and made $17.4 billion in buybacks last year. Darren Woods, Exxon's chairman and chief executive, said this topped the payouts at other Western energy giants. "I have a great sense of pride in what our people accomplished," he said in a statement.

In the fourth quarter, the price of a barrel of Brent crude oil, the international benchmark, was 5 percent lower than it was a year earlier, while natural gas was down more than 60 percent in the key European market and 50 percent lower in Japan and South Korea.

Still, the major energy companies' latest earnings showed that they remained enormously profitable and have been taking steps to enhance the performance of their core businesses.

Exxon, Chevron and other oil companies are making some investments in lower-carbon businesses, but the cash that funds shareholder payouts comes from the production and sale of oil and gas. Exxon said that over the year, output from two key areas, the Permian Basin in the Southwestern United States and Guyana in South America, rose 18 percent.

Both Exxon and Chevron recently made acquisitions that are likely to add to their oil and gas production. Exxon agreed to acquire Pioneer Natural Resources, a leading shale driller, for nearly $60 billion in October, while Chevron reached a deal to take over Hess for $53 billion.

The low-carbon moves that these companies make are usually closely related to their existing businesses. Mr. Woods of Exxon said on a call with analysts Friday that the company was scoping out $20 billion in investments aimed at reducing emissions. Last year, the company paid $4.9 billion for Denbury, a company that owns pipelines for transporting carbon dioxide.

The idea, Mr. Woods said, is to sign up high-emitting factories and other installations along the Gulf of Mexico to take away their greenhouse gases. He said it made sense to use such technologies to try to reduce emissions "rather than tear up and throw away the existing infrastructures and the industries that we have in place."

On Friday, two activist investors withdrew a proposal for shareholders to vote on Exxon's cutting its emissions more quickly. Exxon had sued the investors in federal court to prevent the proposal from going to a vote. One of the investors, Arjuna Capital, called Exxon's move "intimidation and bullying."

On Thursday, Shell, Europe's largest energy company, reported a 26 percent decline in adjusted earnings in the fourth quarter, but still made $7.3 billion. Shell earned $28 billion for the entire year and paid out $23 billion to shareholders in dividends and buybacks, the company said.

Wael Sawan, who became chief executive of Shell last year, said he had cut costs at the company by $1 billion and aimed to cut at least another $1 billion. He is also trimming businesses that have become marginal, like onshore oil production in Nigeria.

Whereas his predecessor, Ben van Beurden, liked to tell a story about his daughter's confronting him at dinner with her views about Shell's role in climate change, Mr. Sawan is not shy about being in the oil and gas business. He said his company was bringing online fields that would add half a million barrels a day of oil equivalent into production by 2025.

"They will enable us to continue providing the energy security that the world needs while delivering cash flow," he said.

Stanley Reed reports on energy, the environment and the Middle East from London. He has been a journalist for more than four decades. More about Stanley Reed

Fossil Fuel Companies Make Billions in Profit as We Suffer Billions in Losses: 2024 Edition

blog.ucsusa.org/shaina-sadai/fossil-fuel-companies-make-billions-in-profit-as-we-suffer-billions-in-losses-2024-edition/

April 17, 2024

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Shaina Sadai

Hitz Fellow

Above: Lahaina, Hawai'i after the devastating August 2023 wildfire that killed more than 100 people and destroyed 2,700 homes.

Last year, I wrote that fossil fuel companies made billions of dollars in profit during 2022 as people around the world suffered billions of dollars in damage from climate and weather related disasters. The climate impacts people around the world experience are connected to the fossil fuel industry's record-breaking profits:

> "The profits made by the oil and gas majors come at the direct expense of all of us and our shared planet. These companies continue to extract more fossil fuels from the ground, lobby for their interests, deceive and misinform the public about climate change, and build new infrastructure to lock us into this continual cycle of extraction, combustion, and the dire consequences it brings. They need to be held accountable for these actions."

Now that all the numbers are in for 2023, we can say that, tragically, this trend continues. Last year was one of extremes, yet again breaking the record for hottest year with an annual temperature 1.48°C above the preindustrial average. Records were smashed in terms of extreme air and ocean temperatures; people around the world experienced wildfires, floods, severe storms, and other disasters. While fossil fuel industry profits were down from their 2022 earnings, these companies still pulled in a dizzying amount of money in 2023, with the combined profits of ExxonMobil, Chevron, Shell, and BP totaling over $100 billion. The CEO of Chevron bragged about the company's record profits and fossil fuel production levels, saying: "In 2023, we returned more cash to shareholders and produced more oil and natural gas than any year in the company's history." The comment shows an atrocious disregard for the fossil fuel industry's harmful impacts on the world and for global efforts to confront climate change and prioritize human rights.

US disasters and disaster response

In 2023, the United States suffered 28 separate weather- and climate-related disasters, the highest number of such events recorded in a single year that each caused over $1 billion in economic damages. Taken together, these disasters caused $92.9 billion in damage. This monetary damage is just a crude measure that doesn't fully account for the loss of life, cultural heritage destroyed, trauma endured, and other types of damage that cannot be described in economic terms. These calamities tragically caused the deaths of 492 people. That figure doesn't capture the full extent of the trauma experienced by survivors of these disasters, many of whom face myriad difficulties in recovering emotionally, physically, and financially long after the time when the news cycle has shifted away from the aftermath of catastrophe.

One of these billion-dollar disasters was the wildfire that devastated Lahaina, Hawai'i. That fire alone killed more than 100 people, destroyed important cultural heritage sites and 2,700 homes, and severely impacted local ecology. The fire also left toxic ash in its wake, the disposal of which has proven problematic. While the role of climate change hasn't been quantified for this fire, we know that climate change is making wildfires more frequent and severe. The history of colonization that still shapes the land to this day also played a role. While the media had only limited coverage of the role of fossil fuels in creating the conditions for such an unusual fire, Maui County is suing fossil fuel producers for deceiving the public about climate change harms they knew their products would cause. The lawsuit notes, for example, that wildfire season is no longer a season, but rather a year-round struggle. Unfortunately, as things currently stand, the fossil fuel companies likely won't have to pay for any of the recovery efforts from the devastation in Lahaina.

In the United States, recovery efforts after disasters are paid for in part by funds from the Federal Emergency Management Agency (FEMA). But with a growing number of disasters and the rising cost of recovery, FEMA does not have enough money to meet the growing need. Vastly underfunded, FEMA has relied on Congress for emergency supplemental funding in recent years to shrink its multi-billion dollar deficit. As my colleague Shana Udvardy wrote, this funding deficit means FEMA has to preserve limited funds for immediate life-saving needs while stalling projects to help with recovery from disasters that happened in previous years. Such deferrals in Congressional appropriations for disaster recovery most severely impact underserved people, including people who are unhoused, displaced, and historically disadvantaged.

Disasters and disaster response around the world

Major climate and weather disasters occurred across the world last year, including the record-breaking cyclone Freddy which devastated parts of Mozambique and Malawi, catastrophic flooding in Libya, severe floods and drought in Kenya, and many more. Thousands of people were impacted by these events and face a long road to recovery.

Global efforts to assist in this recovery are desperately needed and movement is starting to happen. At COP28, the long-awaited loss and damage fund was operationalized. The purpose of this fund is to provide compensation to those impacted by disasters. While operationalizing the fund is a positive step, the funds pledged so far by nations are severely lacking, with a paltry $400 million in the fund so far. This is a drop in the bucket compared to what is needed as climate change continues to make the world less safe. The United States has pledged $17.5 million—an embarrassingly low sum from the world's largest historic emitter and the nation where many of the world's largest fossil fuel companies are headquartered.

Climate Analytics presented a new analysis putting the need for pledges to the loss and damage fund alongside profits of the world's largest oil and gas producers. Their research shows that, in just over three decades (1985-2018), fossil fuel producers made $30 trillion in profit while a partial accounting of damages linked to their products was $20 trillion. This implies that they could have paid for all the climate damage associated with their products—and still walked away with $10 trillion in profit.

It is clear that people around the world are suffering from the harms of fossil fuels, and it is clear that these companies have the money to compensate for economic damages. The question remains, does the political will exist to bridge these issues?

Profiting off climate damage and conflict

While disaster recovery efforts around the world struggle to keep up with community needs, the fossil fuel industry has money to spare, paying out record amounts to shareholders and conducting stock buybacks. This is occurring simultaneously with rollbacks to their climate pledges as we see them again taking the path they have chosen too many times before to prioritize profit over the planet.

The fossil fuel industry's high profits come primarily from the world's continued addiction to its products, which the companies themselves lobby to maintain. But the profits are also buoyed by global conflict. An analysis from Global Witness recently found that, since Russia's invasion of Ukraine, the five largest fossil fuel companies in the United States and Europe have raked in a quarter of a trillion dollars as the conflict drove up energy prices.

While fossil fuel companies profit, people suffer.

It's time to change course

In 2023, heat-trapping emissions from fossil fuels increased by 1.1%. This may sound like a small amount. But, in a world where we have known for decades that these emissions need to decline and that we are far off track from meeting emissions reduction goals, any increase represents a threat to life on this planet. Increases in the fossil fuel production that drives climate change will continue to wreak havoc. Such increases will allow fossil fuel companies to continue making jaw-dropping profits while efforts to fund disaster response—such as FEMA in the United States and the loss and damage fund globally—continue to lag far behind what is needed.

The fossil fuel companies have shown time and time again that they cannot be trusted to do the right thing. They have continued to prove this as they walk back their previous climate pledges even as the impacts of record-breaking heat are causing unimaginable damage around the world. This is why we must keep up public pressure toward a fast, fair phaseout of fossil fuels, consider the role of banking in propping up this system, shine a light on the industry's decades of disinformation and denial, and continue to call for accountability via the courts. Action is needed to ensure that these companies are not allowed to continue to line the pockets of shareholders while people suffer from the devastating impacts their products have caused.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Washington, D.C. 20460

December 9, 1976

MEMORANDUM

SUBJECT: Guidance for determining Acceptability of SIP Regulations in Non-attainment Areas

FROM: Roger Strelow, Assistant Administrator for Air and Waste Management

MEMO TO: Regional Administrators, Regions I-X

The basis for fully approving state-submitted SIP regulations continues to be demonstrated attainment and maintenance of all national ambient air quality standards as expeditiously as practicable. If the plan demonstrates attainment and maintenance, EPA is required to approve the state regulations. EPA cannot disapprove them because they are too stringent or because EPA Considers them not stringent enough (for example, because they are less stringent than a comparable Federal regulation or because they control fewer sources than controlled by Federal regulations), providing the overall SIP shows attainment and maintenance as quickly or quicker than any other available control strategy. If the state plan shows attainment and maintenance, Federal regulations may be revoked at the time of approval.

Especially for oxidant, carbon monoxide, and particulate matter (in areas dominated by urban fugitive dust), control measures required to attain the standards may be technically impossible or socially or economically unacceptable within a short time frame. In this situation, EPA still cannot disapprove state regulations because they are "too stringent," and industry cannot successfully challenge an approval on the ground that the requirements are technologically or economically infeasible. On the other hand, EPA must disapprove the state regulations if they are not stringent enough. The test for approvability of individual regulations is whether they require, at a minimum, all reasonably available controls on a source as expeditiously as practicable. This memorandum seeks to provide guidance as to how to ascertain if state regulations meet these minimum requirements. The use of any given level of control which fails to assure attainment should only be considered to be an interim measure. As control technology improves and as new control measures become feasible for an area, it will be necessary for the SIP to be periodically revised to include these measures until attainment and maintenance can be demonstrated.

1. Reasonably Available Control Measures

a. Stationary Sources

With respect to individual point sources and area sources with defined emission points (i.e., those amenable to the application of "classical" control equipment), reasonably available control technology (RACT) defines the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. Thus, RACT encompasses stringent, or even "technology forcing," requirement that goes beyond simple "off-the-shelf" technology. As noted, RACT is the minimum EPA can accept in non-attainment state plans.

The determination of RACT and the corresponding emission rate, ensuring the proper application and operation of RACT, may vary from source to source due to source configuration, retrofit feasibility, operation procedures, raw materials, and other technical or economic characteristics of an individual source or group of sources. In order to assist the Regions in determining the impact of these variables on RACT, OAQPS is continuing to develop RACT guidance materials (see attached status report). This material describes what can be accomplished with good technology and defines things that should be considered in establishing an emission limit for a specific source of that type. In determining RACT for an individual source or group of sources, the control agency, using the available guidance, should select the best available controls, deviating from those controls only where local conditions are such that they cannot be applied there and imposing even tougher controls where conditions allow. For example, the best available control for a boiler burning coal and bark at a pulp mill is multiclone followed by an electrostatic precipitator (ESP), the two control devices having an overall collection efficiency of 99.5%. However, in areas where the bark or similar fuel has a high salt content as a result of the logs being floated in the estuary portion of the river, it may be that the technological and economic

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* As stated at the outset of this memorandum, the test for approving the entire control strategy – and for EPA thus not having to promulgate any measures – continues to be demonstrated attainment and maintenance of the NAAQS.

problems of installing and operating a large, corrosion resistant ESP may prove unreasonable. More technological and economically feasible controls consisting of a multiclone and ,wet collector designed to withstand the corrosive conditions, and perhaps functioning more effectively on a salt fume than an ESP, depending on the pressure drop employed, may constitute RACT under the conditions cited. In every case RACT should represent the toughest controls considering technological and economic feasibility that can be applied to a specific situation. Anything less than this is by definition less than RACT and not acceptable for areas where it is not possible to demonstrate attainment

As a further assistance to the Regions in defining RACT for the more difficult or the far from textbook situations, OAQPS's Emission Standards and Engineering Division (ESED) will establish a consulting group to support the Regions. This group will include ESED staff but will also include technical expertise from OE and the Regional Offices. In specific instances, the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) may be asked to assist in a RACT determination. The consulting group is being established as a service to the Regions and it should not be looked at as a clearinghouse for regional RACT determinations. These decisions are yours to make. The group is designed to help you as needed on the most difficult cases.

b. Mobile and Area Sources

As with point sources, measures which constitute reasonably available controls for mobile sources and area sources with undefined emission points may represent relatively stringent requirements which in many situations forces the application of measures not previously adopted or implemented in a given area. These measures include vehicle inspection and maintenance, transportation control and land use measures, certain controls on fugitive and reentrained dust, and other measures which may influence customary life styles. They do not include clearly un- reasonable measures such as substantial gasoline rationing. Moreover, what may be reasonable in one area may be un- reasonable in another. For example, while it may be reasonable as a transportation control measure to quickly reduce the number of cars permitted to enter the central business district in a city with a good mass transit system, it would not be reasonable to do this on the same timetable in a city with a poor mass transit system.

2. Documentation

In those situations where the State's control strategy can- not demonstrate attainment it will be necessary for the State to document that their control strategy represents the application of reasonably available control measures to all available source categories. The Region should not approve a control strategy that does not contain sufficient documentation to show that the required control measures are the toughest that are reasonably available for the sources in the area covered by the control strategy.

3. Replacement of Federal Regulation

In some areas the SIPS already contain EPA regulations representing reasonably available controls that generally reflect a national definition of reasonably available controls for that source category and that were arrived at by EPA after proposal and public hearing, (e.g., Stage I and I1 gasoline marketing regulations in 16 AQCRs; transportation control measures in 28 AQCRs).

In these situations there is inherently less flexibility in the definition by the state of reasonably available controls and specific justification will be needed before EPA could ap- prove a regulation which exempts significantly more sources, or which imposes controls significantly less stringent, than the Federal regulations. This justification should document the specific case-by-case economic. technical or other factors which cause the state's regulations, although significantly different from the Federal regulation, to include all that is reasonable for a specific area. (The state regulation would still have to con- form to the criteria outlined for defining reasonable control measures.) Such justification must be provided not only as a basis for approval of the state regulations, but also to protect the enforceability of comparable Federal and state regulations in other areas. In the absence of acceptable justification, the state regulation exempting some sources can be approved as far as it goes and the Federal regulation should remain in effect to cover sources for which the state's regulation does not apply. Of course, nothing should preclude a state from adopting and this Agency approving a regulation which requires more control than the Federally promulgated regulation.

Since it is the Agency's objective to encourage the states to develop and implement regulations to replace EPA regulations, the Agency may approve state regulations that are only marginally different from the Federal regulations without the detailed justification noted above if, in the Regional Administrator's judgment, the impact on emissions differs imperceptibly (less than 5% in cases where it is possible to quantify the difference) from that of the Federal regulations and there is no significant threat of undermining EPA activities elsewhere in the nation. When determining if a state regulation is environmentally equivalent to the Federal regulation, EPA can only look at the particular measure being implemented. In other words, it would be unacceptable to approve a measure requiring significantly less control than the corresponding Federal measure on the basis that other control measures implemented in the same area are significantly more stringent than the comparable Federal measures. In areas where attainment cannot be demonstrated, all reasonable measures on all source categories are needed.

To further encourage states to replace EPA regulations, reasonable additional time generally may be granted to com- ply with replacement regulations providing the new compliance dates (effective dates) are not clearly excessive. We cannot expect a state to adopt regulations which depend upon the prior Federal regulations to alert sources to the steps needed for control, except in those cases where the state regulation is substantially identical to the Federal regulation which it replaces. On the other hand, granting of additional time must be done with care so as not to undermine the action-forcing role of firm deadlines in EPA efforts elsewhere. The use of a "good faith efforts" test will be appropriate in some circumstances

4. Conclusion

In concluding, I would like to reiterate the fact that the air quality standards are not being attained in many of these RACT areas. Therefore, we cannot relax the intensity of the air pollution control effort. We should ensure that all sources contributing to the nonattainment situation are required to implement restrictive available control measures even if it requires significant sacrifices.

cc:`Mr. Tuerk, Mr. Barber, Mr. Legro, Mr. Bonine, Mr. Hidinger.