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Quantifying Methane Emissions from Oil Fields in the Central Valley of CA

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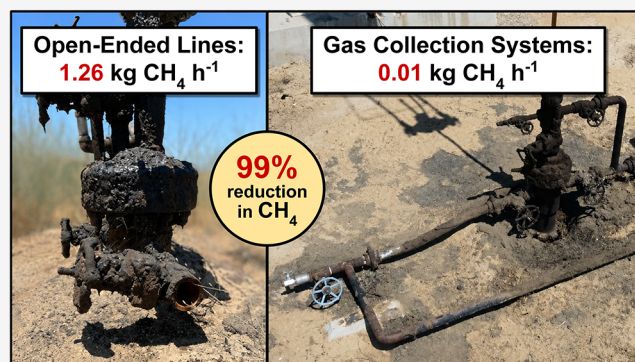
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ABSTRACT: In 2024, California was the eighth-largest producer of crude oil in the U.S. by volume with ~50,000 active wells. Working with the California Energy Commission, we measured methane (CH_4) emissions from 172 actively producing oil wells (219 total observations with 47 repeat measurements) either with or without casinghead gas collection systems (GCS) in two oil fields near Bakersfield in Kern County. We also measured benzene (C_6H_6) emissions at a subset of wells to assess C_6H_6 to CH_4 ratios. The mean mass-based ratio for C_6H_6 : CH_4 was 7.8×10^{-7} with a mean benzene emission rate of 0.9 mg h^{-1} . Wells with an open-ended line (OEL) emitted ~100-fold more methane on average than wells with a GCS: 1.26 kg h^{-1} and 0.01 kg h^{-1} , respectively. The prevalence of wells with a GCS rose sharply with increasing oil and gas production, rising from 36% for wells producing <2 barrels of oil equivalent per day (boed) to 97% for wells producing ≥ 15 boed. The top 5.7% highest-emitting wells were responsible for $\geq 50\%$ of total methane emissions from casinghead gas. Methane emissions were overwhelmingly dominated by wells without a GCS, accounting for 98.5% of total casinghead gas emissions across both fields. Capturing gas from these wells would eliminate almost all of the methane emissions we detected.

KEYWORDS: methane, benzene, oil and gas wells, wellheads, open-ended lines, casinghead gas collection system, casinghead gas, heavy oil production, bakersfield, kern county



INTRODUCTION

Nearly one-third of anthropogenic methane is emitted during the extraction and use of fossil fuels, including oil and natural gas (O & G).¹ Methane is ~86 times more potent than carbon dioxide during the first two decades after release, and reducing fossil-based emissions is one of the quickest ways of slowing warming.² The United States is producing record amounts of crude oil,³ a surge that underscores the need to identify and reduce the accompanying methane emissions. Methane emissions occur throughout the oil and gas supply chain—from production to homes.^{4–8} Identifying and quantifying these emissions is necessary for reducing them.

In 2024, the U.S. had over 918,000 actively producing oil and natural gas wells.⁹ Potentially, up to four million more wells are classified as idle, inactive, or abandoned.¹⁰ Since 1977, approximately 240,000 oil and gas wells have been drilled in California, with more than 40,000 wells remaining active and producing more than 100 million barrels of oil annually.¹¹ Recent ground-based studies have estimated site-level methane emissions from oil and gas wells in eight basins across nine states—but not in California.¹² This study contributes to a growing body of data on methane emissions

from oil and gas wells, many of which are low-producing wells, and identifies a key opportunity for reducing these emissions.

Gases produced alongside crude oil, known as associated gas, are often rich in methane and nonmethane volatile organic compounds (NMVOCs),¹³ and are typically captured for use by oil and gas operators or processed and sold.¹⁴ However, due to infrastructure constraints or limited capacity in gas processing facilities, some operators vent these gases—known as casinghead gas—at the wellheads to relieve pressure and promote higher oil production.¹⁵ In addition to methane, each well is a potential source of NMVOCs, including propane, butane, pentane, and carcinogenic benzene.¹⁶ Benzene has been detected in gas emitted from active and abandoned wells across the United States,¹⁷ potentially posing risks to the health of nearby populations.¹⁸ Approximately 70,000

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residents in Kern County (8.5% of the total population) live within 1 km of an active oil and gas well.¹⁹

Ground-based measurements and industry-derived emission factors have been used to estimate methane and NMVOC emissions from oil and gas wells and fields, but key well-specific sources remain poorly characterized at the component level. Omara et al. compiled 240 site-level emission factors across eight U.S. basins (not including CA) and estimated national emissions from low producing oil and gas wells (≤ 15 barrels of oil equivalent per day, boed).¹² Mellqvist et al. further characterized greenhouse gas and air toxic emissions from oil production in Kern County, including areas encompassing the Poso Creek and Kern Front oil fields.^{22,23} At the component level, Deighton et al. estimated emissions of methane and NMVOCs (e.g., benzene) from open vents and natural gas gathering lines of ultralow producing (< 1 boed) oil and gas wells in the Appalachian Basin.²⁰ The American Petroleum Institute published default emission factors for active oil wells with vented casinghead gas and production-normalized methane intensities for wells practicing thermally enhanced oil-recovery, a method commonly used in California.²¹

Direct measurements of methane and NMVOCs from oil wells remain limited, particularly for casinghead gas, which is a substantial source of methane emissions from oil production.²⁴ The results that we report quantify these emissions systematically. As part of the California Energy Commission-funded Super-eMitters of Methane detection using Aircraft, Towers, and Intensive Observational Network (SUMMATION) project,²⁵ we conducted the most comprehensive in situ assessment to date of wellhead methane emissions in California and provided, to our knowledge, the first robust estimate of venting well prevalence in heavy-oil fields. We present new measurements from 172 active oil wells in the Central Valley of CA, including wells venting through open-ended lines (OELs) and those equipped with gas collection systems (GCSs). Combined with field-wide surveys of casinghead gas infrastructure, our measurements make it possible to estimate field-level methane emissions from a key component of oil production.

MATERIALS AND METHODS

We adopt standardized terminology from energy (e.g., American Petroleum Industry) and regulatory (e.g., Bureau of Safety and Environmental Enforcement) authorities. As part of a pumpjack or progressive cavity pump, a wellhead is defined as the piping, casing, tubing, and connected valves that protrude above the ground, ending where the flow line connects to a wellhead valve.²⁶ Associated gas, or casinghead gas, is gas that is released during the initial separation stage at oil-producing wells.²⁶ An OEL refers to any valve, excluding safety relief valves, that is open to the atmosphere, either directly or through open piping (see Figure S1A,B).²⁶ A GCS includes any infrastructure that transports gas from a well site to another location for treatment, storage, processing, or disposal (see Figure S1C).²⁶ The age of a well is determined by its earliest “spud date” available, the date on which drilling commenced.²⁷ We standardize oil and gas production based on barrels of oil equivalence (boe), calculated from the conversion of 1 barrel of oil equaling 4.197 Mcf of natural gas produced in the San Joaquin Basin (SJB).¹³ We designate wells as either oil or gas wells based on a gas-to-oil ratio (GOR) of 6 Mcf of gas per 1 barrel (bbl) of oil produced, as defined by the U.S. Energy Information Administration; wells with a GOR ≤ 6 Mcf gas bbl⁻¹ are considered oil wells.⁹ Wells that produce an annual GOR of ≤ 0.3 Mcf gas bbl⁻¹ are designated as heavy-oil wells, as defined by the U.S. Environmental Protection Agency (EPA).²⁸

Study Area

Approximately 80% of California’s active oil and gas wells are in Kern County, which accounts for 72% of annual CA oil production.²⁹ Of the Kern County’s 68 producing oil fields, Poso Creek and Kern Front are the eighth and ninth largest, respectively, by the total volume of oil produced annually (Figure S3).²⁹ From 2022 to 2024, Poso Creek and Kern Front had an estimated 2,064 actively producing oil wells, each field having an active footprint of ~ 23 km² (Figure S16). Marginal wells (i.e., wells producing ≤ 15 barrels of oil equivalent per day) account for 88% of all active oil wells across both fields (Figure 1).²⁹ During our study, the majority of wells in Poso Creek and Kern

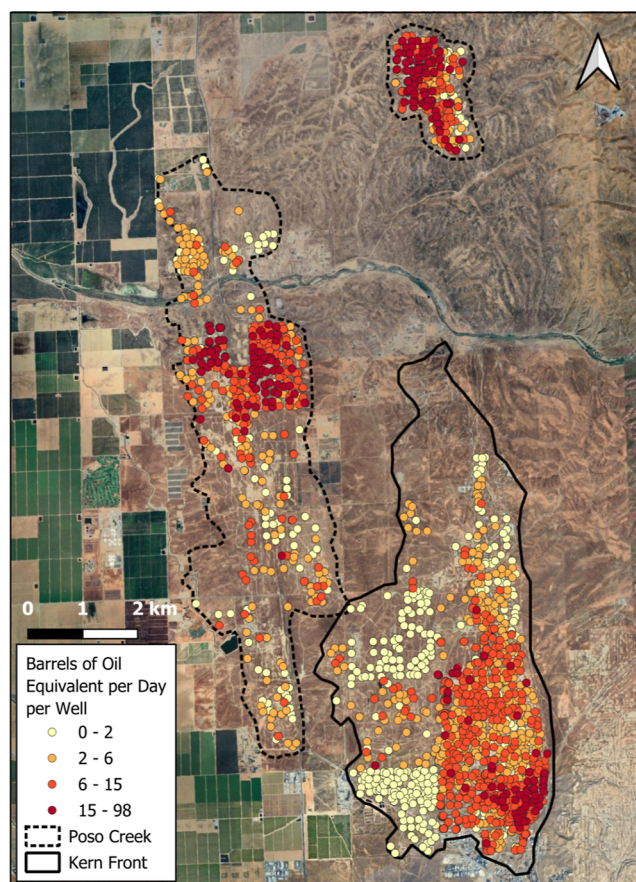


Figure 1. Map of the study area with 2,064 oil wells colorized by volume of oil and gas production in barrels of oil equivalent per day (boed). Field boundaries represent the greater footprint of both active and inactive well sites. See Figure S16 for an estimate of active well footprint. Data source: California Geologic Energy Management Division (CalGEM) Well Production Summary Reports spanning 2022–2024.²⁹

Front were classified as heavy-oil wells (84%), based on oil and gas production reported to the California Geologic Energy Management (CalGEM) Division, with less than 0.1% operating as gas wells (Figure S4).²⁹

In Situ Measurements

The presence of an OEL or GCS was quickly identified as a key indicator of whether a leak would likely be present. We measured methane and benzene emissions from oil wells during six field campaigns between 2022 and 2024. We made 219 in situ measurements of methane from 172 oil wells, including 127 pumpjacks and 45 progressive cavity pumps, in two fields we herein denote as Fields 1 and 2. Lease names and well locations are withheld to maintain operator anonymity. We measured 67 wells in Field 1 and 105 wells in Field 2, of which 97% and 59% were pumpjacks,

respectively. Our measured wells produced slightly less (~20%) barrels of oil equivalent per day than the average well across the two fields overall (Table S15). Of the total number of wells measured, 26% had a GCS.

We made 15 benzene measurements from 13 wells, the majority of which were from Field 1 ($n = 10$). Relationships between benzene and coemitted alkanes were evaluated using linear regression. Wells were randomly selected for benzene measurements using Jenks natural breaks³⁰ classification of previously measured wells to capture a representative range of low- and high-methane-emission cases. This approach was used to assess whether methane emissions could serve as an indicator of benzene emissions from the casinghead gas in these fields.

We revisited a subset of 23 wells over approximately 14 months to assess temporal variability in methane emissions (61 total visits with a mean of 2.7 visits per well). A coefficient of variation (CV) was calculated for each well to assess temporal variability. We report the median value due to inflated CVs caused by low-emitting wells. We used Spearman's rank correlation to evaluate well persistence, comparing emission rates from the first visit with the last.

Methane emissions from 13 wells were measured during periods of both active pumping and not pumping to assess changes in emissions, with the same well measured on two separate occasions, yielding 14 total comparisons. Measuring oil wells during different periods of activity is challenging because of the intermittent nature of oil production in these fields; several hours can pass before a well starts or stops pumping. For this study, if a well started or stopped pumping during a visit, an additional measurement was performed. The distributions of methane emissions during each operational status were non-normal (Shapiro–Wilk test: $p = 0.01$); therefore, a paired Wilcoxon signed-rank test was used to compare emissions between the two pumping states. Although pumping status was recorded at the time of each measured well and evaluated statistically, pumping status was not incorporated into field-wide estimates because well activity is intermittent and not available at sufficient temporal resolution for the full well population.

Instrumentation and Quantifying Emission Rates

We measured gas emission rates using (1) a standalone gas analyzer and TEC (The Energy Conservatory) Minneapolis Duct Blaster (hereafter, Analyzer-Duct Blaster)³¹ or (2) a SEMTECH (Sensors Emissions Measurement Technology) HI-FLOW 2 fugitive methane sampler (hereafter, SEMTECH).³²

The Analyzer-Duct Blaster system utilized a calibrated airflow device (the TEC Duct Blaster) paired with an Aeris MIRA (Mid-Infrared Absorption) ULTRA and AROMA-VOC (model ARVOC-191E, RSO, Entanglement Technologies, Inc.) gas analyzer for measuring methane and benzene concentrations, respectively. This method was previously demonstrated by Lebel et al. to quantify methane leaks from residential natural gas water heaters.^{33–35} The TEC Duct Blaster included 3.6 m of flexible ducting with an internal diameter of 240 mm and a fan that could be precisely controlled up to 1,500 cubic feet of air per minute (CFM), as reported by the Duct Blaster flow gauge. The fan was placed ~6 in. from the emission source and stabilized with sandbags. The air temperature inside the duct was measured using a HOBO Type K Thermocouple Temp Data Logger (Model UX100-014 M by Onset).³⁶ Flow rates through the duct varied depending on its configuration; bends introduced flow resistance that reduced the maximum achievable flow rate. For measurements in this study, the Duct Blaster was used with a typical range of flow between 833 and 1,455 CFM.

Emission rates with the Analyzer-Duct Blaster were estimated based on the measured flow rate and the difference between diluted concentrations inside the duct and background concentrations upwind of the source. The same Tygon or PTFE (Polytetrafluoroethylene) tubing (6.35 mm OD) was used for both background and duct measurements at each well. PTFE is chemically resistant to benzene and was used for all measurements with the AROMA-VOC analyzer.³⁷ Backgrounds were measured 5–10 m upwind of the wellhead and 0.3 m off the ground. At least one background

measurement was taken at each well immediately before and/or after steady-state measurements (i.e., for a measurement of casinghead gas emissions). The sample tube was then secured inside the ducting at the opposite end of the fan and connected directly to an Aeris analyzer or diaphragm pump (GAST Manufacturing) with a flow rate of 7 LPM.³⁸ The GAST pump supplied the Aeris and AROMA via a T-connection before venting to the atmosphere downwind. Wind direction was determined prior to each background air measurement and assumed to remain steady throughout the measurement. The total volumetric flow of methane and benzene was calculated using eq 1

$$Q_{\text{GAS}} = \frac{([\text{GAS ppb}]_{\text{DB}} - [\text{GAS ppb}]_{\text{BKG}})}{1,000,000,000} \times Q_{\text{DB}} \times 28316.8 \quad (1)$$

where Q_{GAS} is the total volumetric flow of methane or benzene in mL min^{-1} from the gas source; $[\text{GAS ppb}]_{\text{DB}}$ and $[\text{GAS ppb}]_{\text{BKG}}$ are the concentrations inside the duct blaster and upwind of the source (the background or BKG), respectively, Q_{DB} is the volumetric flow (CFM) of the Duct Blaster averaged over the measurement period, and last the conversion from cubic feet to mL based on 28,316.8 mL cuft^{-1} . Volumetric flows were converted and reported in standard temperature and pressure (0 °C and 1 atm) using measured temperature in the duct or ambient temperature at the time of the measurement. Volumetric flow rates were converted to mass-based flow rates according to the ideal gas law. In total, 132 measurements were made with the Analyzer-Duct Blaster from 96 wells.

The second method used to quantify emission rates of methane employed a SEMTECH HI-FLOW 2, an integrated system that combines high-flow sampling with gas sensing to provide real-time emission rates ($\text{L CH}_4 \text{ min}^{-1}$).³² The SEMTECH calculates emission rates by multiplying methane concentration by the total flow. Similar to the Analyzer-Duct Blaster, the SEMTECH assumes the background methane concentration remains stable during the sampling period. Eighty-seven measurements were made with the SEMTECH from 76 wells, of which 44 measurements were below the instrument's limit of detection (LOD) of 0.6 g of $\text{CH}_4 \text{ h}^{-1}$.

Following the approach of Robertson et al.,³⁹ SEMTECH emissions below the LOD were estimated by randomly assigning values from a uniform distribution between 0 and 0.6 g h^{-1} . This approach ensures that sites below the LOD are included when estimating field-wide emission rates and is consistent with prior well-level methane studies. The approach is likely conservative given the assumption that wells below the method detection limit (MDL) resemble the lower tail of the same log-normal distribution of wells above the MDL. In contrast, the Analyzer-Duct Blaster method does not have a fixed LOD as emission rates are quantified based on concentration enhancements over background; therefore, detection sensitivity depends on background variability and instrument precision. Controlled releases of methane confirmed a method detection limit (MDL) as low as 0.05 g of $\text{CH}_4 \text{ h}^{-1}$ for the Analyzer-Duct Blaster. Only four wells measured with the Analyzer-Duct Blaster reported an emission rate below this MDL and were included in the full data set of measured wells.

We verified consistency between these two methods of measuring methane emissions by performing consecutive measurements to evaluate instrument agreement and well-level repeatability. Five wells were measured with the Analyzer-Duct Blaster and SEMTECH during the same visit and differed by a mean of only 0.12 kg $\text{CH}_4 \text{ h}^{-1}$ (paired t-test, 95% CI: -0.02–0.26, $p = 0.07$), corresponding to a mean bias of only 4.6% between instruments, and a strong linear agreement ($R^2 = 0.997$, $p < 0.001$; Figure S8). We also tested the repeatability of well-level emissions at 37 wells with the Analyzer-Duct Blaster by conducting ≥ 2 measurements during the same visit and pumping status (Figure S13). Overall, repeated measurements were consistent within wells, with a median CV of 4.9%.

Visual Survey of Wellheads

We made additional observations of wells, beyond those directly measured, to increase spatial coverage across the two fields. This data

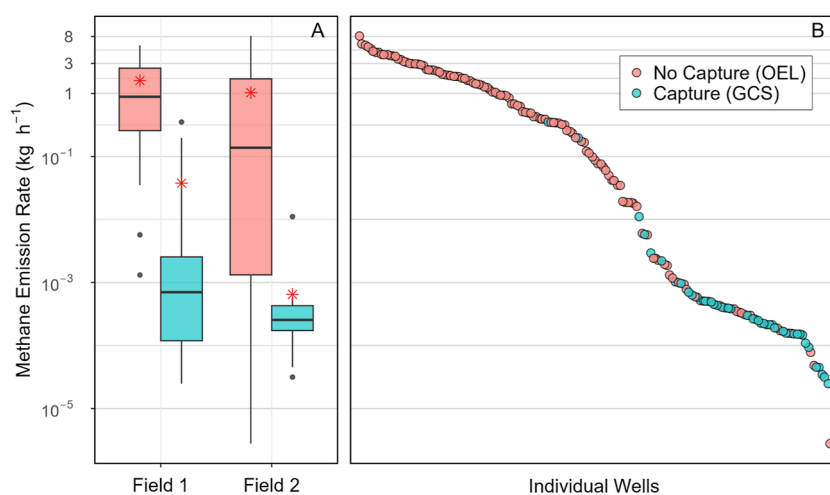


Figure 2. Distribution of measured methane emission rates ($n = 172$) in each field with (aqua) and without (red, OEL) gas collection systems (GCS). Each boxplot (panel A) shows the 25th, 50th, and 75th percentiles as well as a red asterisk for the mean emission rate. Each point in panel B corresponds to measurements made at an individual well. Wells measured more than once display the emission rate from the first visit and wells measured more than once during the first visit (consecutive measurements) display the mean emission rate.

set, coupled with measured wells, is used in the next section for assessing GCS prevalence and later for estimating total field-wide emissions. In total, 268 wells were visually assessed, of which 65% were observed aerially using a Da-Jiang Innovations (DJI) Mavic 3 quadcopter. Aerial observations were structured by lease—the smallest spatial unit within each oil field—to ensure a statistically representative coverage across the fields. We selected leases that contributed to the top 50% of actively producing wells (by cumulative proportion of total wells in each field).

Considering the number of wells per lease, we set an observational target of 20% per lease, randomly selected and excluding wells assessed from previous visits. In practice, not all selected wells could be observed, resulting in some leases having observation fractions lower or higher than the 20% target. Despite this variation, 21% ($n = 440$ wells) of all wells across the two fields were surveyed for the presence of a GCS via ground or aerial observations. Of the total wells surveyed, 57% ($n = 250$) had a GCS and 13% ($n = 57$) were progressive cavity pump wells. The locations of 43 randomly selected wells could not be determined due to inaccurate GPS coordinates in the CalGEM database. In these cases, the nearest unvisited actively producing well was chosen as a replacement and observed for the presence of a GCS.

Categorizing Daily Oil and Gas Production and Estimating GCS Prevalence

Informed by prior evidence that low-producing wells often have disproportionately higher methane emissions,¹² we estimated GCS prevalence as a function of oil and gas production (boed) by combining direct observations of 440 wellheads with 36 months (2022–2024) of oil and gas production data from CalGEM (see Section S12). Wells from both fields were aggregated and categorized into four classes of boed following Bowers 2022: <2 , ≥ 2 and <6 , ≥ 6 and <15 , and ≥ 15 .⁴⁰ We then used Monte Carlo simulation with bootstrapping to estimate the proportion of wells equipped with a GCS in each category, accounting for production variability from each well's historical mean and standard deviation using eq 2

$$C_i = \begin{cases} < 2 & \text{if } P_{i,j} < 2 \\ 2 - 6 & \text{if } 2 \leq P_{i,j} < 6 \\ 6 - 15 & \text{if } 6 \leq P_{i,j} < 15 \\ > 15 & \text{if } P_{i,j} \geq 15 \end{cases} \quad P_{i,j} \sim TN(\mu_p, \sigma_p, a = 0), j = 1, 2, \dots, N \quad (2)$$

where C_i is the production category for well i , and P_i is the boed randomly sampled from a truncated normal distribution based on the well's three-year mean production, μ_p , and standard deviation, σ_p . Each iteration, j , was repeated 10,000 times, N (see Figure S9 for a detailed flowchart). Rather than assigning wells to a fixed production category, this resampling approach accounts for uncertainty in production by allowing wells near category thresholds to be assigned to different categories across iterations.

Next, the proportion of wells with a GCS, G_C^{final} , in each production category was calculated using eq 3

$$G_C^{\text{final}} = \frac{1}{N} \sum_{j=1}^N G_{C,j} \quad (3)$$

where $G_{C,j}$ is the proportion of wells with a GCS in category C for iteration j . We then calculated the mean proportion of wells equipped with a GCS in each category and the corresponding 95% confidence interval across all iterations. For each category, we also calculated the mean methane emission rate and intensity, boed, and well age. Distributions of GCS prevalence by field and production category were compared using Cohen's d , where smaller values indicate greater overlap in GCS prevalence between fields.^{41,42}

We also evaluated whether methane intensity ($\text{kg CH}_4 \text{ boe}^{-1}$) and well age predicted the presence of a GCS using binary logistic regression. Methane intensity was log-transformed to account for right skewness, and well age was mean-centered. Because GCS prevalence may be associated with production, we also evaluated the relationship between the well age and production rate (boed) using linear regression.

Estimating Well-Level and Field-Wide Methane Emissions

Total field-wide methane emissions were estimated from an aggregated data set of 2,064 actively producing oil wells across both fields. Each well was assigned a production category using eq 2. Rather than assuming a fixed GCS prevalence per category, we sampled from a uniform distribution bound by the category-specific 95% confidence interval (Table S4, Field rows "F1.F2"). Capture status (GCS or OEL) was then randomly assigned to each well via a Bernoulli draw using the sampled prevalence. Methane emission rates were subsequently resampled from the empirical distribution of measured wells with the same production category and capture status (see Figure S11 for a detailed flowchart). This approach preserves the variability and heavy-tailed structure observed in the measured data set. Incorporating repeat measurements of only a small fraction of wells (i.e., wells visited more than once) could bias estimates of field-wide emissions; therefore, we only use emission rates from the first

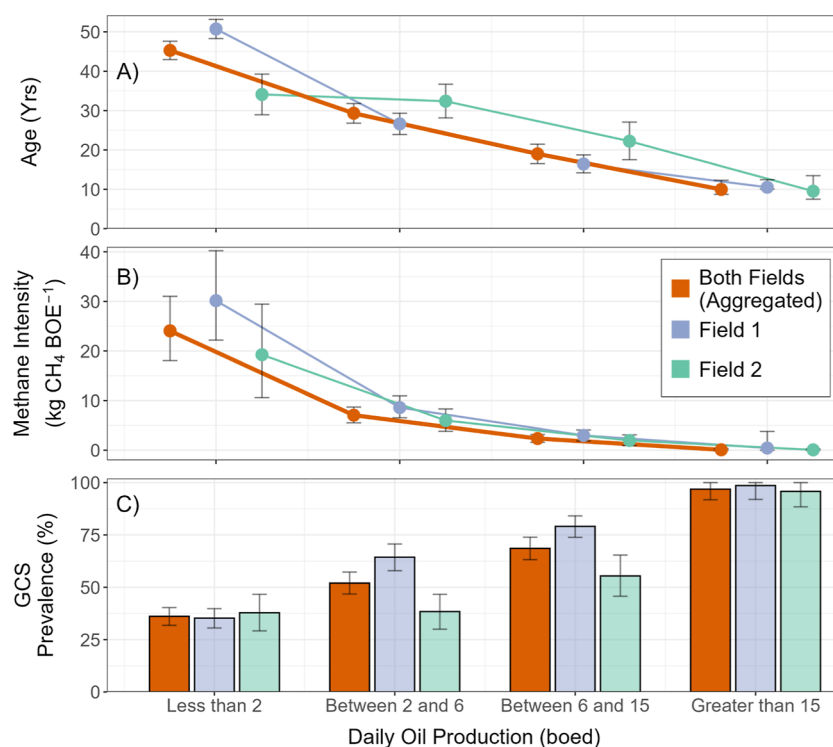


Figure 3. Summary of well age (years, panel A), methane intensity (kg CH₄ boe⁻¹, panel B), and GCS prevalence (% panel C) as a function of daily oil and gas production (*x*-axis; boed). Age and GCS prevalence are estimated from 440 wells across both fields. Methane intensity is estimated from measured wells only (*n* = 172). Orange lines and bars signify the aggregated data set of wells from Field 1 (blue, *n* = 246) and Field 2 (green, *n* = 194). Uncertainty is reported as the 95% CI and derived from a bootstrapped Monte Carlo of 10,000 iterations based on oil and gas production between years 2022 and 2024.

visit when estimating well-level and field-wide emissions. Total field-wide emissions were estimated using eq 4

$$E_{\text{Mean}} = \frac{1}{N} \sum_{i=1}^N \left[\sum_C \left(\sum_{j=1}^{W_{C,\text{With}}} E_{C,\text{With},j} + \sum_{k=1}^{W_{C,\text{Without}}} E_{C,\text{Without},k} \right) \right] \times \frac{24 \times 365}{1000} \quad (4)$$

where E_{Mean} is the total estimated annual emissions in metric tons of methane per year, *N* is the number of iterations, *C* is the category of boed, $W_{C,\text{With}}$ and $W_{C,\text{Without}}$ are the number of wells in category *C* with and without a GCS, respectively, and $E_{C,\text{With},j}$ and $E_{C,\text{Without},k}$ are methane emissions for wells *j* and *k* in kg h⁻¹, with and without a GCS. Total emissions were converted from kg h⁻¹ to t y⁻¹. We then estimated a well-level emission rate from each iteration of the Monte Carlo before estimating the overall well-level mean and 95% confidence interval. Confidence intervals were defined empirically as the 2.5th and 97.5th percentiles of the distribution of the Monte Carlo simulation.

RESULTS

Methane Emission Rates

Methane emission rates were strongly right-skewed, with most wells exhibiting relatively low emissions and a small number of disproportionately higher-emitting wells (Figure 2). The top 10% highest-emitting wells accounted for ≥50% of total methane emissions from all measured wells. The highest emission rates measured in Fields 1 and 2 were 5.8 and 8.2 kg CH₄ h⁻¹, respectively. Wells with an OEL emitted nearly one hundred times more methane on average than wells with a GCS: 1.26 (95% CI: 0.99–1.55 *n* = 127) kg CH₄ h⁻¹ and 0.013 (95% CI: 0.001–0.03, *n* = 45) kg CH₄ h⁻¹, respectively

(*p* < 0.001, unpaired Wilcoxon test). In Field 1, wells with an OEL emitted a mean of 1.6 (95% CI: 1.2–2.1, median 0.9, *n* = 52) kg CH₄ h⁻¹, 60% more than wells with an OEL in Field 2 (1.0 kg CH₄ h⁻¹, 95% CI: 0.7–1.4, median 0.1, *n* = 75, *p* < 0.001, unpaired Wilcoxon test). Pumpjacks with an OEL (*n* = 87) had a mean emission rate of 1.6 (95% CI: 1.3–2.0) kg CH₄ h⁻¹, 3-fold higher than venting progressive cavity pump wells (mean 0.5 kg h⁻¹, 95% CI: 0.2–0.8 kg h⁻¹, *n* = 40). Wells of both types equipped with a GCS emitted ≤0.015 kg CH₄ h⁻¹ on average.

Benzene Emission Rates

Benzene emissions were observed across all measured sites and overall exhibited a positive correlation with coemitted alkanes. Benzene emissions ranged from 0.01 to 5.1 mg h⁻¹ with a mean of 0.9 (95% CI: 0.2–1.7, median 0.2, *n* = 13) mg h⁻¹ across both fields (Table S11). Wells in Field 1 had a mean emission rate of 1.1 (95% CI: 0.3–2.1, median 0.4) mg C₆H₆ h⁻¹. Benzene emissions were positively correlated with methane (log–log *R*² = 0.51, *p* = 0.02) and ethane (log–log *R*² = 0.78, *p* = 0.001) for the same wells in Field 1 (*n* = 10; Figure S12). The mean C₆H₆:CH₄ and C₆H₆:C₂H₆ ratios (kg kg⁻¹) in Field 1 were 1.0 × 10⁻⁶ and 1.2 × 10⁻³, respectively. Benzene emissions were measured at only three wells in Field 2 with a mean of 0.06 mg h⁻¹ (median 0.07) and a mean C₆H₆:CH₄ and C₆H₆:C₂H₆ ratio (kg kg⁻¹) of 2.2 × 10⁻⁸ and 1.8 × 10⁻⁵, respectively.

Benzene emissions followed a highly skewed distribution, with low-producing wells exhibiting disproportionately higher benzene emissions compared to higher producing wells. Measured wells producing <2 boed reported a mean emission rate of 1.4 mg C₆H₆ h⁻¹ with an accompanying intensity of

29.6 mg C₆H₆ boe⁻¹ ($n = 5$). Comparatively, wells producing between 2 and 6 boed emitted a mean of 0.6 mg C₆H₆ h⁻¹ with an intensity of 4.6 mg boe⁻¹ ($n = 6$), and wells producing between 6 and 15 boed emitted 12 $\times$ less benzene per unit of time on average than wells producing < 2 boed (0.1 mg h⁻¹, $n = 2$) and nearly one hundred times less per barrel equivalent (0.3 mg boe⁻¹; Table S10). No wells producing more than 15 boed were measured for benzene emissions. The top 3 highest emitting wells (23%) accounted for 79% of the total benzene emissions from 13 measured wells.

Operational and Temporal Methane Emissions

Methane emissions were broadly similar between pumping and nonpumping conditions, with emissions slightly higher during nonpumping periods (paired Wilcoxon test, $n = 14$, $p = 0.04$; Table S1 and Figure S6).

Methane emissions from wells revisited over time exhibited only modest temporal variability and strong persistence across repeat measurements (Figure S5). The median CV of all revisited wells was 10.3% (IQR: 4.5–18.9%, $n = 23$), with a range of 0.7–113%. In Field 1, the median CV was 8.6% (IQR: 3.6–12.2%, $n = 12$), less than half the median CV in Field 2 (19.2%, IQR: 7.5–54.4%, $n = 11$). Most high-emitting wells remained high emitters over the study period: 5 out of 6 wells in the top quartile remained in the top quartile at their final visit. Overall, ranks of high-emitting wells over time were strongly preserved with little change between the first and last visits ($\rho = 0.83$, $p < 0.001$). Detectable emissions of methane were found from all revisited wells.

Venting Prevalence and Production Category Statistics

GCS prevalence was positively correlated with daily oil and gas production (boed, $p < 0.001$; Table S8); the proportion of wells with a GCS increased steadily from 36% (95% CI: 32–40%) to 97% (95% CI: 92–100%) for wells producing < 2 and ≥ 15 boed, respectively (Figure 3C, Table S4).

Older wells exhibited higher methane intensities (kg CH₄ boe⁻¹, Spearman's $\rho = 0.46$, $p < 0.001$) and were less likely to be connected to a GCS (Figure 3). Among wells with measurable emissions, a 10-fold increase in methane intensity was associated with a 75% lower odds of a well having a GCS (odds ratio = 0.25, logistic regression, $p < 0.001$; Table S7). Well age was significantly associated with GCS presence, with each additional year associated with 8% lower odds of GCS presence (OR = 0.92, $p < 0.001$). Wells producing < 2 boed had a mean age of 45 years (95% CI: 43, 48) and emitted 24 (95% CI: 18–31) kg CH₄ boe⁻¹ on average, 2.5 orders of magnitude greater than wells producing ≥ 15 boed with a mean age of 10 years (95% CI: 9–12) and intensity of 0.1 (95% CI: 2×10^{-4} –0.3) kg CH₄ boe⁻¹ (Figure 3A,B; Table S4).

Total Annual Field-Wide Methane Emissions from Casinghead Gas

Methane emissions from casinghead gas were overwhelmingly attributed to low-producing wells (<15 boed) with OELs. Total annual emissions from both fields were estimated at 9,370 (95% CI: 8,170–10,590) t of CH₄ y⁻¹ from 2,064 actively producing oil wells (Figure 4). Field 1 accounted for 64% of total emissions with 6,000 (95% CI: 5,130–6,920) t CH₄ y⁻¹, compared with 3,360 (95% CI: 2,760–4,020) t y⁻¹ from Field 2. The lowest producing wells (<2 boed) were responsible for most emissions (40%), with an estimated 3,740 (95% CI: 2,710–4,880) t CH₄ y⁻¹, whereas the highest producing wells (>15 boed) were responsible for 0.7% of total

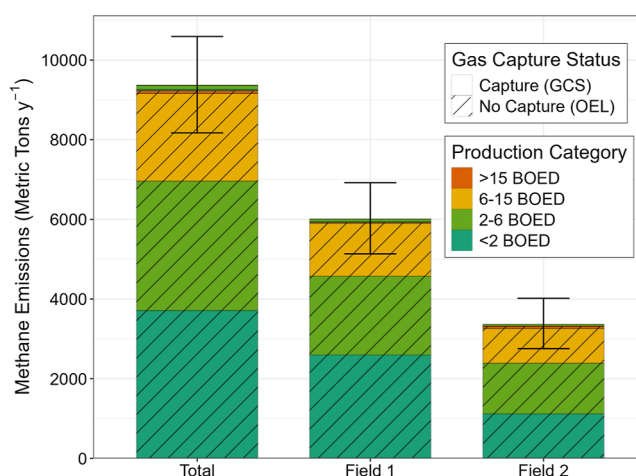


Figure 4. Total annual methane emissions of casinghead gas from an aggregated dataset of 2,064 oil wells in Fields 1 and 2. Uncertainty is displayed as the 95% CI from a bootstrapped Monte Carlo simulation with 10,000 iterations. Each bar is divided into oil and gas production categories (<2, 2–6, 6–15, and >15 boed). Emissions from wells with a gas collection system are represented by a solid color and emissions from wells with an OEL have a diagonal pattern.

emissions (70 tons CH₄ y⁻¹, 95% CI: 1–380; Table S12). The majority of emissions were driven by sites without a GCS (9,230 t y⁻¹, 95% CI: 8,030–10,460); although only 41% of wells across these two fields were estimated to be without a GCS, they accounted for 98.5% (95% CI: 97.7–99.1%) of total casinghead gas emissions.

The estimated mean well-level emission rate of casinghead gas was 0.52 (95% CI: 0.45–0.59) kg CH₄ h⁻¹ well⁻¹ across the two fields. Wells producing less than 2 boed are estimated to emit 0.76 (95% CI: 0.56–0.99) kg CH₄ h⁻¹ well⁻¹, 25 $\times$ higher than nonmarginal wells producing greater than 15 boed (mean 0.03 kg h⁻¹ well⁻¹, 95% CI: 2×10^{-4} –0.15; Table S12). Marginal wells (≤ 15 boed) had a mean well-level emission rate of 0.60 (95% CI: 0.52–0.68) kg CH₄ h⁻¹.

Cumulative Distribution of Emissions

The cumulative distribution of methane emissions from casinghead gas exhibited similarly heavy-tailed distributions commonly found in oil and gas leakage studies in which a small fraction of sites account for the majority of emissions. Across Monte Carlo iterations, an estimated 5.7% (95% CI: 5.0–6.3%, $n = 118$) of all wells across both fields ($N = 2,064$) accounted for $\geq 50\%$ of total casinghead emissions (Figure 5). For wells with a GCS ($n = 1,216$, 95% CI: 1,145–1,288), 2% (95% CI: 1.2–3.0%, $n = 24$) of wells accounted for $\geq 50\%$ of total emissions, compared with 13.5% (95% CI: 12.3–14.8%, $n = 115$) of wells with an OEL ($n = 848$, 95% CI: 776–919). Measured and field-wide estimates were similar within each capture-status group in terms of the fraction of sites contributing $\geq 50\%$ of emissions (OEL and GCS), but differed by nearly 2-fold when all wells were pooled across capture status (Table S13). See Section S11 for more information on how the cumulative fraction of emissions differed for wells of each capture status and measured and field-wide data sets.

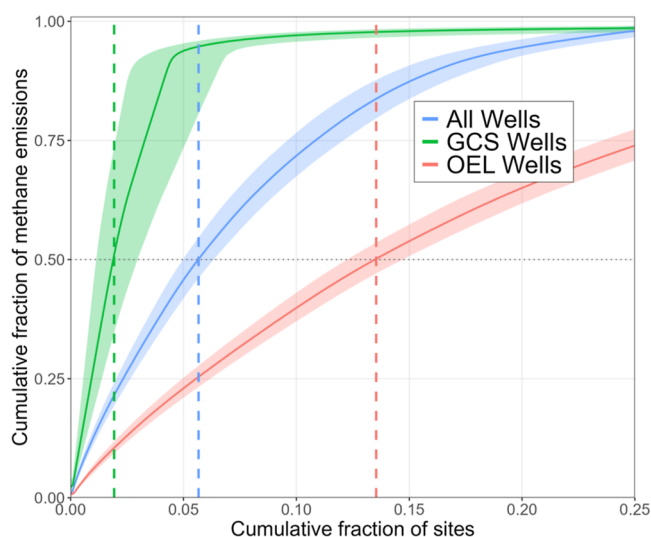


Figure 5. Cumulative distribution of methane emissions from casinghead gas for all active oil wells in Fields 1 and 2 (derived from a Monte Carlo simulation with 10,000 iterations). Curved green and red lines represent the cumulative distribution of methane emissions for wells with a gas collection system and open-ended line, respectively. Blue lines represent the distribution of methane emissions for the aggregated dataset of all wells ($N = 2,064$). Vertical dotted lines represent the cumulative fraction of wells responsible for $\geq 50\%$ of total emissions for each group of wells (GCS, OEL, and all). Shaded regions along the solid curved lines represent the 95% confidence intervals across 10,000 iterations.

DISCUSSION

Evaluation of API Emission Factors for Vented Casinghead Gas

The API compendium reports a default emission factor of $0.85 \text{ kg CH}_4 \text{ h}^{-1}$ for vented casinghead gas from active heavy-oil wells.⁴³ This is slightly lower than our mean emission rate of casinghead gas from measured wells with an OEL ($1.26 \text{ kg CH}_4 \text{ h}^{-1}$), but within the 95% CI of venting wells in Field 2 ($0.7\text{--}1.4 \text{ kg CH}_4 \text{ h}^{-1}$). The API methodology assumes that only 4.7% of casinghead gas is vented from thermally enhanced oil wells, resulting in a production-normalized methane intensity of $0.2 \text{ kg CH}_4 \text{ bbl}^{-1}$. Based on an average annual oil production of 5.2 million barrels y^{-1} in Fields 1 and 2 between 2022 and 2024, the API intensity would suggest an annual emission rate of only $1,030 \text{ t CH}_4 \text{ y}^{-1}$, 9 times lower than our estimated field-wide total. Recognizing that we were only capturing some of the emissions from each field, inventory estimates based on these venting assumptions may therefore substantially underestimate total methane emissions in oil fields where gas collection systems are underutilized. Based on our estimate of 848 (95% CI: 776–919) wells with OELs across the two fields, the API's default emission factor would suggest a total emission rate of $6,314 \text{ t CH}_4 \text{ y}^{-1}$ from venting wells in these two fields, 1.5 times less than our estimate and comparatively more accurate than using the API's production-normalized emission factor. Although the API emission factor for methane from vented casinghead gas is slightly lower than our estimate for measured wells, we found that the API estimate provides a reasonable estimate of casinghead gas emissions from active oil wells when the prevalence of venting wells is unknown.

Contribution of Casinghead Gas Emissions to Total Site-Level Emissions

Casinghead gas emissions may represent a substantial fraction of total site-level emissions from low-producing oil wells. As reported by Omara et al., marginal oil wells ($\leq 15 \text{ boed}$; $\text{GOR} \leq 6 \text{ Mcf bbl}^{-1}$) had a mean site-level emission rate of 1.6 (95% CI: $0.8\text{--}2.6$, median 0.5 , $n = 31$) $\text{kg CH}_4 \text{ h}^{-1}$.¹² Unlike our study, which focused on specific wellhead components, their estimates include additional on-site sources such as tanks, separators, flares, pneumatic devices, and other fugitive equipment. Using our mean ($1.05 \text{ kg CH}_4 \text{ h}^{-1}$) and median ($0.25 \text{ kg CH}_4 \text{ h}^{-1}$) estimates of casinghead emissions from oil wells producing $\leq 15 \text{ boed}$ to compare with those reported by Omara et al., casinghead emissions may account for between 50 and 66% of total site-level emissions from oil wells. This comparison should be interpreted as conditional because the measurements of oil wells reported by Omara were collected across five U.S. basins, which may influence gas production and venting behavior.

Omara et al. further developed a national emissions estimate of 0.8 (95% CI: $0.5\text{--}1.2$) $\text{kg CH}_4 \text{ h}^{-1}$ per low production well site for 565,000 oil and gas well sites in the US. Their national site-level estimates are from predominantly gas wells measured using mobile lab techniques, therefore, potentially capturing additional leak sources. The lower per-well emission rate in our study ($0.52 \text{ kg CH}_4 \text{ h}^{-1}$, 95% CI: $0.45\text{--}0.59$) may also be due in part to the lower gas-to-oil ratio (GOR) of approximately 300 v. 2,000 scf bbl^{-1} in Omara et al. With a lower GOR, there is simply less gas to emit.

Methane Emissions from Ultralow Producing Oil Wells

Methane emission rates from ultralow producing wells (ULP, $<1 \text{ boed}$) are highly variable and remain poorly characterized relative to higher producing wells. Deighton et al. estimated a mean of 0.2 (95% CI: $0.05\text{--}0.3$, median 0.05) $\text{kg CH}_4 \text{ h}^{-1}$ from 20 ULP oil wells (i.e., wells with a $\text{GOR} \leq 6 \text{ Mcf bbl}^{-1}$), ranging from 0 to $0.9 \text{ kg CH}_4 \text{ h}^{-1}$. Similar to wells in our study, these measurements were from testing individual well components rather than entire well sites, with several measurements made from sources beyond the OEL (e.g., leaks around the well casing). Deighton et al. specifically noted six wellheads with open vents and one with a GCS. Their mean emission rate for ULP wells with an OEL was 0.3 (max 0.9 , median 0.15 , $n = 6$) $\text{kg CH}_4 \text{ h}^{-1}$, 3x less than venting wells in our study producing $<1 \text{ boed}$ (mean 0.9 , $n = 11$), but similar to our median of $0.09 \text{ kg CH}_4 \text{ h}^{-1}$. Deighton's estimate for wells with an OEL is within our 95% CI of $0.15\text{--}1.9 \text{ kg h}^{-1}$, a relatively wide range due to our small sample size of ULP wells and their highly skewed distribution. Our results further highlight the variability in emissions from ultralow producing wells.

Ultralow producing wells contribute a substantial portion of total casinghead emissions despite their relatively limited oil production. In Kern Front and Poso Creek, these wells are estimated to account for 20.5% of total casinghead emissions—approximately $1,920 \text{ t CH}_4 \text{ y}^{-1}$ (95% CI: $1,340\text{--}2,590$)—while accounting for only 10% of wells and 0.6% of total oil and gas production between 2022 and 2024. Based on the EPA's social cost of $\$1600$ per metric ton CH_4 (i.e., the cost of economic damages to climate, health, agriculture, and infrastructure with a discount rate of 2%),⁴⁴ the annual cost of damages from ultralow producing wells add up to approximately $\$3$ million. By comparison, an average 31,000 barrels of

oil per year from ULP wells in Kern Front and Poso Creek, valued at \$82 per barrel (production volume and value is based on estimates from 2022 to 2024), corresponds to a gross annual oil value of approximately \$2.5 million from ultralow producing wells. The social cost of emissions to keep these wells operating is roughly equivalent to the economic value of the oil produced. Comparatively, wells producing between one and fifteen boed produced a significantly higher gross value of approximately \$250 million per year, similar to the annual gross value of wells producing greater than fifteen boed (\$180 million).

Comparing Benzene Emissions from Oil and Gas Wells

Deighton et al. similarly observed a highly skewed distribution of benzene emissions from ultralow-producing (<1 boed) oil ($n = 5$) and gas ($n = 11$) wells in the Appalachian Basin. Their highest measured benzene emission rate from oil wells accounted for 80% of total measured oil well emissions, whereas their highest-emitting gas well accounted for 70% of total gas well emissions. These distributions, although from a smaller sample size, follow a similar pattern to measured oil wells in our study, with the top three highest emitting wells accounting for nearly 80% of total measured benzene emissions ($n = 13$).

The highest reported benzene emission rate from oil wells in the Appalachian basin (492 mg h^{-1}) is over 2 orders of magnitude greater than the highest emitting well we measured from oil wells in the San Joaquin Basin (5 mg h^{-1}). Deighton et al. reports a mean emission rate of 122 (median: 25) $\text{mg C}_6\text{H}_6 \text{ h}^{-1}$ from five oil wells—substantially higher than our estimated 0.9 (median: 0.2) $\text{mg C}_6\text{H}_6 \text{ h}^{-1}$ from 13 oil wells producing between 1 and 11 boed. This is likely a result of the different chemical properties of oil produced in these two basins. The average $\text{C}_6\text{H}_6:\text{CH}_4$ ratio (kg kg^{-1}) from oil wells in the Appalachian Basin was 1.1×10^{-3} , approximately 3 orders of magnitude higher than our estimated ratio of benzene in casinghead gas (7.8×10^{-7}). Heavy crude oil has a relatively low gravity and generally contains fewer aromatic and volatile hydrocarbons than lighter oils found in the Appalachian Basin.^{45–47}

Using our total estimated emission rate of methane and the ratio of benzene-to-methane in casinghead gas, we estimate a total benzene emission rate of ~ 7 (95% CI: 6–8) kg y^{-1} from the casinghead gas of two fields in Kern County, CA. Although this is relatively small compared with some other sources, the proximity of oil wells in Kern County suggests that many low-emitting sources may contribute to cumulative exposure in nearby communities.⁴⁸ Further measurements and exposure assessments are needed to evaluate the potential implications of chronic exposure to low-level benzene emissions from oil wells in this region.

Comparing Total Field-Wide Estimates to Previously Reported Emissions for Poso Creek and Kern Front

Total field-wide estimates from mobile plume surveys may underestimate emissions in these fields, particularly where emissions are small or intermittent. Mellqvist et al. estimated total methane emissions from Poso Creek and Kern Front to be $4,120 \text{ t y}^{-1}$ between 2018 and 2019, whereas a subsequent survey in 2021 estimated emissions from Kern Front alone to be approximately $4,380 \text{ t y}^{-1}$, nearly identical to the previous estimate for both fields combined. Both estimates are approximately $2\times$ less than our field-wide emission estimate of casinghead gas alone. Consistent with this discrepancy, a

2020 aerial methane survey of oil fields across the San Joaquin Valley noted that Kern Front and Poso Creek had some of the highest numbers of methane plumes in the region.⁴⁹

These discrepancies highlight the biases associated with each method of quantifying emission sources that vary temporally and spatially. Ground-based methods are generally better suited for detecting relatively small and persistent emission sources from individual components, such as vented casing-head gas, that may not be cumulatively detected downwind. In contrast, mobile and aerial surveys have proven capable of quantifying large, often infrequent, emission sources, such as separators or malfunctioning flares, that would otherwise go unnoticed from ground-based surveys.⁵⁰ As part of the SUMMATION project, several aerial methane surveys were conducted in Fields 1 and 2 during our ground campaign. Combining ground-level measurements with aerial surveys will provide a more comprehensive estimate of the total methane emissions from these fields.

CONCLUSIONS

Our findings demonstrate the opportunity to substantially reduce methane emissions from oil and gas production by capturing casinghead gas that is currently vented across oil fields in California and elsewhere. Expanding the use of relatively low-cost gas-collection systems already deployed today across these fields could mitigate a large fraction of the emissions observed in our study.

Our findings further demonstrate the value of direct, well-level measurements for characterizing emissions from low-producing, spatially dispersed wells that may be under-represented in national inventories. Under Subpart W of the Greenhouse Gas Reporting Program (GHGRP), owners and operators of petroleum and natural gas facilities are required to report emissions when total facility emissions exceed $25,000 \text{ t CO}_2 \text{ e yr}^{-1}$; however, the findings of our study suggest that these inventories substantially underestimate the magnitude of vented casinghead gas in these regions. In 2023, the total reported emissions of vented casinghead gas for the entirety of the SJB were only 61 tons of methane, of which Kern County was responsible for 53 tons. These figures are orders of magnitude lower than our estimated emissions of casinghead gas from just two fields in Kern County. For comparison, these county-wide estimates are equivalent to just one well emitting $6 \text{ kg CH}_4 \text{ h}^{-1}$, similar to one measured well- in our data set, which showed persistent emissions between 4.5 and 6.4 kg h^{-1} from six visits over 10 months.

Lastly, our findings show that an accurate field-wide estimate for the number of wells without a GCS will help reduce uncertainties in emission inventories and better inform targeted mitigation strategies going forward. This would be particularly beneficial when assessing the potentially high environmental costs of maintaining low-production wells.

ASSOCIATED CONTENT

Data Availability Statement

Measurement data, Monte Carlo simulations, and analysis code supporting this study are available in the Dryad Digital Repository at <https://doi.org/10.5061/dryad.05qftfks>. The repository includes an R script that reproduces the results (tables, figures, and statistics) reported in the manuscript and Supporting Information.

Supporting Information

The Supporting Information is available free of charge at <https://pubs.acs.org/doi/10.1021/acsestair.6c00126>.

Example photographs of wellheads with open-ended lines and gas collection systems; oil and gas production by field and well type in Kern County; temporal variability and pumping-status comparisons of methane emissions; methane controlled-release tests, detection limits, and comparisons of the Analyzer–Duct Blaster and SEMTECH systems; gas collection system prevalence and predictors; methods and results for field-wide methane emissions; benzene emission measurements; Analyzer–Duct Blaster repeatability tests; cumulative emission distributions; methods for cleaning CalGEM production-data; well-productivity profiles; active-well spatial footprints; and comparison of Carbon Mapper observations with ground-based methane estimates (PDF)

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Notes

The authors declare no competing financial interest.

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