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Methane Emissions from the Natural Gas Transmission and Storage System in the United States

Daniel J. Zimmerle,*,† Laurie L. Williams,‡ Timothy L. Vaughn,† Casey Quinn,† R. Subramanian,§ Gerald P. Duggan,† Bryan Willson,† Jean D. Opsomer,∥ Anthony J. Marchese,† David M. Martinez,† and Allen L. Robinson§

†Energy Institute and Department of Mechanical Engineering, Colorado State University, Fort Collins, Colorado 80524, United States

‡Department of Physics and Engineering, Fort Lewis College, Durango, Colorado 81301, United States

§Center for Atmospheric Particle Studies (CAPS) and the Department of Mechanical Engineering, Carnegie Mellon University, Pittsburgh, Pennsylvania 15213, United States

∥Department of Statistics, Colorado State University, Fort Collins, Colorado 80524, United States

S Supporting Information

ABSTRACT: The recent growth in production and utilization of natural gas offers potential climate benefits, but those benefits depend on lifecycle emissions of methane, the primary component of natural gas and a potent greenhouse gas. This study estimates methane emissions from the transmission and storage (T&S) sector of the United States natural gas industry using new data collected during 2012, including 2,292 onsite measurements, additional emissions data from 677 facilities and activity data from 922 facilities. The largest emission sources were fugitive emissions from certain compressor-related equipment and "super-emitter" facilities. We estimate total methane emissions from the T&S sector at 1,503 [1,220 to 1,950] Gg/yr (95% confidence interval) compared to the 2012 Environmental Protection Agency's Greenhouse Gas Inventory (GHGI) estimate of 2,071 [1,680 to 2,690] Gg/yr. While the overlap in confidence intervals indicates that the difference is not statistically significant, this is the result of several significant, but offsetting, factors. Factors which reduce the study estimate include a lower estimated facility count, a shift away from engines toward lower-emitting turbine and electric compressor drivers, and reductions in the usage of gas-driven pneumatic devices. Factors that increase the study estimate relative to the GHGI include updated emission rates in certain emission categories and explicit treatment of skewed emissions at both component and facility levels. For T&S stations that are required to report to the EPA's Greenhouse Gas Reporting Program (GHGRP), this study estimates total emissions to be 260% [215% to 330%] of the reportable emissions for these stations, primarily due to the inclusion of emission sources that are not reported under the GHGRP rules, updated emission factors, and super-emitter emissions.

INTRODUCTION

The recent dramatic growth in production and utilization of natural gas creates potential economic, climate, energy security, and public health benefits. However, climate benefits depend critically on lifecycle emissions of methane, the primary component of natural gas and a potent greenhouse gas.[1] Methane emissions for the Unites States natural gas system have been estimated using both top-down and bottom-up approaches. Currently, the most complete bottom-up inventory of natural gas system emissions is the 2012 U.S. Environmental Protection Agency's (EPA) Greenhouse Gas Inventory (GHGI).[2] It estimates an overall system-wide methane loss rate of 6.2 Tg/yr of methane, or 1.3% of methane transported (Supporting Information (SI), Section 16) and that the transmission and storage sector (T&S) is the largest emitting segment of the natural gas industry,[2] accounting for about one-third of methane emissions.

Recent top down studies using aircraft-, tower-, ground-based sensing and atmospheric transport models[3−7] suggest that the GHGI may underestimate methane emissions from the oil and gas industry. However, attribution to particular sites or even sectors can be challenging for top-down atmospheric studies, while bottom-up estimates such as the GHGI are limited by sample size, possible sample bias, and measurement limitations. Additionally, Brandt et al.[8] argue that bottom-up inventories

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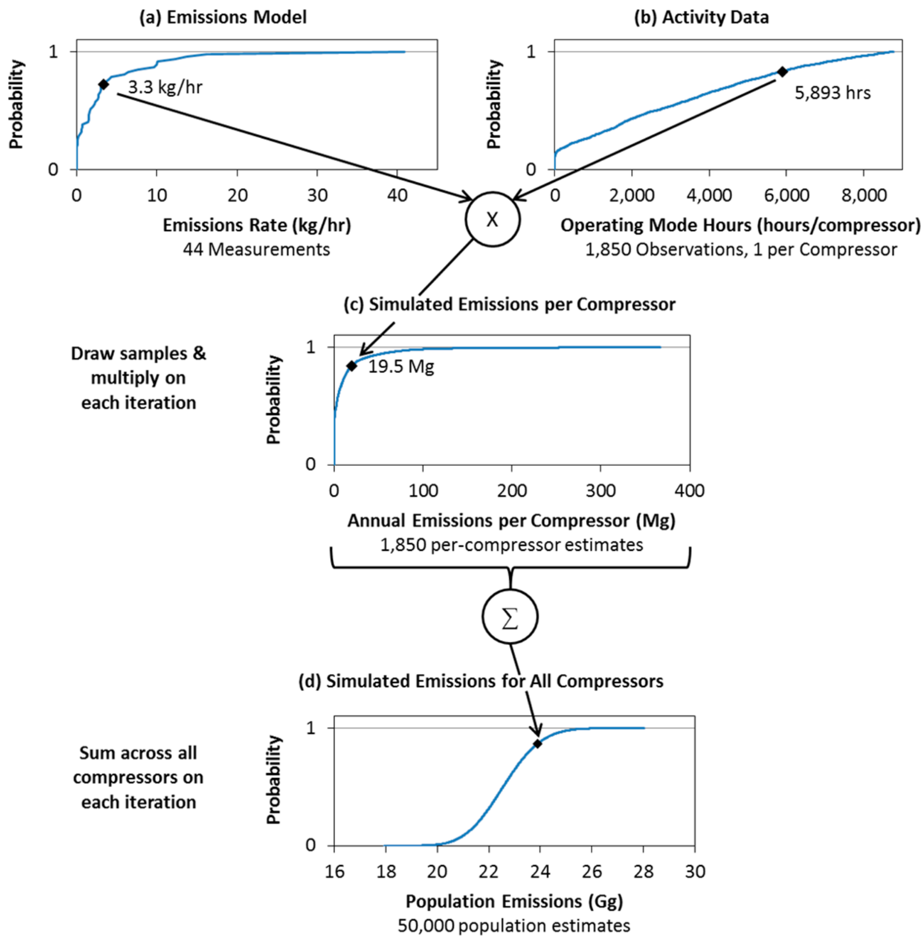

Figure 1. Schematic of an emission submodel (rod packing vent emissions for reciprocating compressors in operating mode for partner facilities) to illustrate the overall modeling approach. This model is based on cumulative distribution functions (a) containing 44 emission rate measurements from the field measurement campaign and (b) showing operating mode hours, from partner data, for the 1,850 reciprocating compressors in this portion of the model. On each Monte Carlo iteration, an emission rate is drawn from (a) for each compressor and multiplied by the operating hours for that compressor, as shown by the arrows, and to produce (c), a distribution of emissions per compressor. Following each of the 50,000 Monte Carlo iterations, population emissions are computed by summing simulated emissions for all compressors to produce a distribution of emissions as shown in (d).

consistently underestimate methane emissions and that a small number of "super-emitters" could be responsible for a large fraction of the emissions. Recent measurement studies have also found significantly skewed distributions for component-level emissions, including detailed surveys of exploration and production well sites,[9] pneumatic controllers,[10,11] liquid unloadings,[12] and distribution facilities.[13] Additional studies, using local atmospheric measurements, have identified super-emitters at both well sites[14]and gathering facilities.[15]

Quantifying the contribution of large emission sources at the component or facility level requires substantial data to define both the proportion of components or facilities with high emissions and the magnitude of those emissions. Existing emissions inventories (e.g., EPA GHGI) are often based on relatively small data sets, e.g., the GHGI for T&S is based on emissions data from only 15 compressor stations, less than 1% of the total station population. Recently, large new emissions and activity data sets have become available for T&S, including field measurements[16] and extensive data from the EPA's Greenhouse Gas Reporting Program (GHGRP),[17] but these data have not yet been incorporated into national estimates like the GHGI.

This study defines the T&S sector as the natural gas system infrastructure between two custody transfer points—the receipt meter between the gathering and processing sector and the transmission system, and the delivery meter between the transmission system and the distribution system (commonly called a "city gate") or industrial end user (SI, Section 3). The T&S sector contains both interstate and intrastate infrastructure, including compressor stations, pressurized pipeline networks, metering and regulation stations, and supporting equipment. This study estimates emissions from compressor stations associated with the T&S sector and connected to underground storage fields. These facilities can be equipped with gas scrubbers, separators, after-coolers, dehydrators, storage tanks, gas-driven pneumatic devices, valves, and connectors.

The GHGI[2] estimate for the T&S sector is largely based on activity and emissions data collected in the early 1990s. For example, many of the emission factors are from the 1996 study by the Gas Research Institute,[18] with updates of centrifugal compressor emissions and activity from a 2010 study by ICF.[19] GHGI estimates transmission station and compressor counts based upon ratios of stations and compressors to pipeline miles from 1992 data, the baseline year, which are then scaled using

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current pipeline miles.[20] There have been substantial changes to the United States natural gas system over the past decade due to the development of shale gas and other factors, raising questions about the representativeness of the data sets underlying the GHGI.

This study develops a new estimate of T&S methane emissions based upon new data for emissions, equipment census, and operations. Results are compared to the GHGI and the GHGRP. For T&S, stations which emit more than 25,000 t of CO_2 equivalent annually are required to report to the GHGRP.

METHOD

This study utilized probabilistic emission and activity models and Monte Carlo methods, as in Ross,[21] to estimate emissions and associated uncertainty. These methods propagate the variability of input emissions and activity data through to a distribution of methane emission estimates that we term the "study model estimate" (SME) for the T&S sector.

The emission modeling approach is described in Figure 1, using rod packing emissions for reciprocating compressors in operating mode as an example. Each emission category was modeled using empirical cumulative distribution functions (CDFs) constructed with emissions and activity data obtained in a field measurement campaign,[16] data from six partner companies who are major T&S operators, and public data from the GHGRP program. In total, the model is based on new emissions data for 677 facilities and activity data from 922 facilities (SI, Table S6-b), representing more than one-third of all United States T&S facilities. None of these data, to our knowledge, have been used in previous national estimates. Emissions categories are based on those defined by the GHGRP and include compressor isolation and blowdown valves, seal vents, and rod packing vents; pneumatic devices; component leaks; and tanks (SI, Section 4). Facilities are divided into multiple groups for simulation (SI, Section 6). For each emission category in each group of facilities, each Monte Carlo iteration provides a single emission estimate obtained by drawing an emissions rate(s) from the appropriate emission CDF(s) and combining it—typically multiplying—with the appropriate activity data (e.g., number of compressors). This process was repeated 50,000 times, and these iterations were combined to develop a distribution of emissions estimates for each category for each group of facilities. These estimates were then combined using Monte Carlo methods to develop a distribution of estimates for the entire sector.

Emissions Models. Seventeen emissions models (in addition to super-emitter and exhaust models, below) were developed from 2,292 new onsite measurements of individual emission sources. Of these, 1,279 measurements were collected during a six month field measurement campaign at 45 T&S facilities operated by six partner companies,[16] and the remaining 1,013 measurements were made during 2012 by three of the partner companies as part of their greenhouse gas reporting activities, using instruments and protocols aligned with the project measurement protocols described by Subramanian et al.[16] Emission categories are detailed in the SI, Section 4, and the origin of all measurements is documented in CDFMaster.xlsx in the SI zipped file.

A detailed analysis of the field measurement study data can be found in a recent paper published by the authors,[16] but key results are included here. A crucial question is whether onsite measurements accurately represent facility emissions. To address this, the field study simultaneously measured methane emissions using two established, independent techniques — comprehensive onsite measurements and downwind tracer flux—to verify that the comprehensive onsite surveys captured all major sources. In addition to measuring sources included in the GHGRP, the onsite protocol also required measurements in all compressor operating modes (e.g., "not operating pressurized") and sources (e.g., dry seal vents) that are not included in the GHGRP, restricted the type of measurement instruments that could be utilized, and used engineering estimation for unmeasured emission sources. Tracer flux methods estimate the facility level emission rate by comparing the downwind concentrations of methane to those of tracer gases released from the facility at a known rate.[22]

For 38 facilities with paired onsite and tracer flux measurements, onsite and tracer flux measurements agreed to within the experimental uncertainty. The agreement between these two independent methods creates confidence that the onsite measurements captured most methane emissions and therefore allows emissions at T&S facilities to be modeled in detail using the category-specific activity and emission data. Category-specific modeling supports detailed understanding of the drivers behind emissions, and differences between this study, the GHGI, and the GHGRP. Two facilities with paired onsite and tracer flux measurements were identified by the tracer flux technique as having emissions greater than 200 standard cubic feet per minute (SCFM) and are treated as super-emitters in the model (see below). Standard conditions are defined as 60 °F and 1 atm.

The equipment-level emission data are highly skewed. Figure 2 presents cumulative distribution functions (CDFs) of the emissions data for the 17 emission models developed from field study and partner data (SI, Table S7-b). A long tail is readily evident in most models. In 12 of the 17 models, the maximum measured emission rate is at least double the 97.5% fractile of the distribution. The inset plot shows the fraction of aggregate measured emissions in each model attributable to the largest

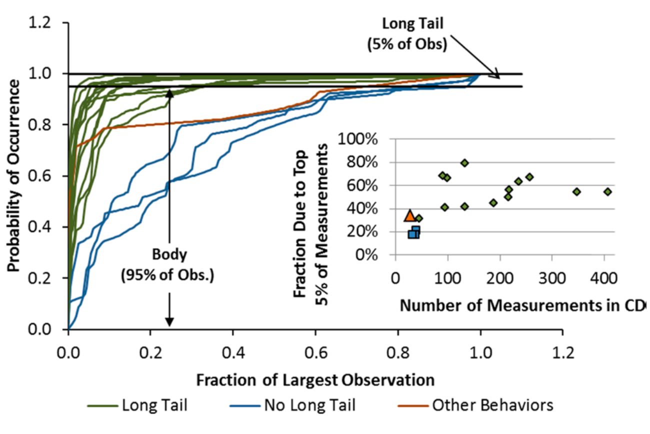

Figure 2. Normalized cumulative distributions of the 17 emission models developed from data collected in this study (SI, Section 7). Inset illustrates the fraction of all measured emissions due to the largest 5% of measurements. Green lines/symbols indicate models with substantial "long tail" behavior, where 5% of measurements are responsible for >30% of total measured emissions. Blue models are substantially less skewed. The orange model exhibits other behavior, namely, a high zero offset present in field measurement data. Inset illustrates that skewed behavior is detected in all models containing more than 90 observations and detected in no model containing less than 40 observations.

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5% of measurements. In 13 models, 5% of measurements account for at least 30% of total emissions, and in 8 models, more than 50% of total emissions. The inset illustrates that the highly skewed character is in every model containing more than 90 observations but in no model containing less than 40 observations. This highlights the importance of large data sets, such as the one used here, to accurately characterize the long tail on emissions distributions. Conversely, for the four models which *do not* exhibit a long tail, these models may underestimate emissions. These models include rod packing vents in one operating mode, wet and dry seal vents, and tank vents.

Since the GHGRP specifies measurement and reporting methods all reporters must use, the mean of reported emissions in each emissions category should be approximately equal between large subpopulations of facilities. However, an examination of data reported to the GHGRP indicated that reported emissions from nonpartner facilities were, on average, approximately 1.4 times larger than that those reported by partner facilities (SI, Table S8-a). Differences were particularly pronounced in categories where the GHGRP requires direct measurement, such as reciprocating compressor venting (1.8 times larger), tank vents (4.6 times larger), and centrifugal compressor venting (7.7 times larger). A difference in reported emissions suggests emissions are impacted by differences in equipment, operational methods, or maintenance practices between partner and nonpartner facilities. Therefore, SME emission models used to analyze nonpartner facilities were modified to account for the reported emission differences, using scaling and differential methods described in the SI, Section 8. Similarly, different models for pneumatic device counts were developed for partner and nonpartner facilities to capture significant differences in pneumatic device utilization (SI, Section 9).

Models for engine and turbine exhaust methane emissions were based upon data underlying EPA standard *Compilation of Air Pollutant Emission Factors* (AP-42)[23] and additional measurements provided by the study partners. AP-42 source data were filtered to include only measurements with complete machine type information and direct measurements of methane. These were combined with partner measurements, particularly for four-stroke, rich burn engines, to develop exhaust emission factors (SI, Section 10).

Finally, when insufficient data existed to develop new models for an emission category, emission factors from the GHGRP were utilized (e.g., intermittent bleed pneumatics and wellhead components, see SI, Section 7).

Activity Models. Activity models are based on data from 922 T&S facilities, including detailed site configuration data for the 686 T&S facilities operated by the six partner companies, and data for 236 nonpartner facilities reporting to the GHGRP. The partner company transmission facilities represent ≈56% of the interstate transmission facilities reported to the U.S. Federal Energy Regulatory Commission (FERC) under Form 2.[24] Study partner activity data included facility counts, compressor and prime mover descriptions, compressor operating hours in three operating modes (operating/not operating pressurized/not operating depressurized), and component counts for pneumatics and storage wells. Compressor and paired prime mover descriptions determine compressor fugitive and exhaust methane emissions, which contribute a major portion of emissions in the T&S segment.[2]

Differing levels of activity information were available for different facilities, ranging from comprehensive data for many study partner facilities to essentially no information for nonpartner facilities not reported to the GHGRP. To account for differing information detail, the model divided the T&S sector into five activity data sets, termed *Lanes*, and a hierarchy of models was developed to estimate emissions for each lane. For partner facilities with complete activity data—including compressor type, operating hours, pneumatic device counts, etc.—activity data were used directly in the model, as shown in Figure 1. Where activity data were incomplete, ambiguous, or absent, activity data were estimated from activity data for similar facilities with known data.

Super-Emitter Emissions. In addition to the equipment-level emissions models, this study also explicitly modeled facility-level "super-emitters". During the field measurement campaign, two facilities were classified as super-emitters due to elevated emissions observed by tracer flux methods which were not measured using onsite measurements or were inaccurately measured with portable acoustic meters. At these facilities, onsite observers indicated that venting was likely due to an anomalous condition, such as gas leaking through a faulty isolation valve. Due to the difficulties in measuring these types of sources with onsite surveys, they are not fully captured in the long tails of equipment-level emissions distributions. To account for these emissions, this study modeled super-emitter emissions at the facility level, utilizing an emissions distribution developed from tracer flux measurements and a frequency model representing the probability of identifying a super-emitter within a small sample population. These models are shown in Figure 3 and in the SI, Section 14. The frequency model was developed by simulating the sampling process used in the field study, i.e., simulating the probability of finding one super-emitter in a random sample of 45 facilities from the available study population of 686 partner facilities. This process produces a probability distribution and confidence interval

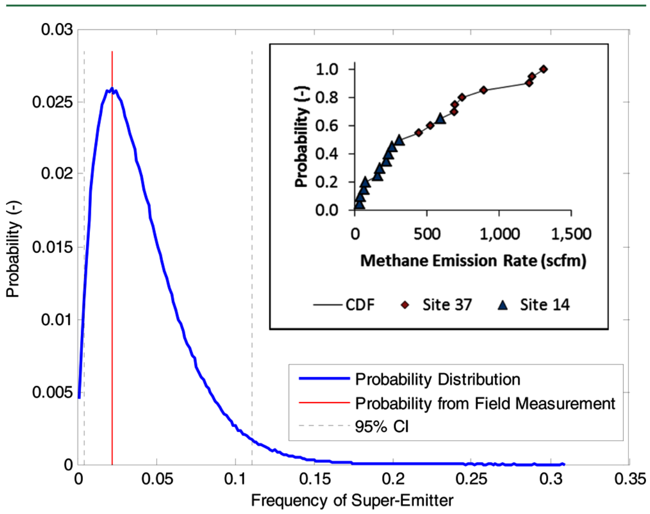

Figure 3. Super-emitter model. Outer plot illustrates the frequency distribution model for super-emitters based upon the probability of finding one super-emitter in 45 randomly sampled facilities from a population of 686 facilities. The mode of the distribution (red line) lies at the probability observed in the field measurement campaign (2.2%). The mean of the distribution is at 4.1%, indicating that approximately 1 in 25 facilities exhibits super-emitter emissions during any given hour of the year. Inset figure illustrates the emission rate model utilized to model super-emitters. The mean of the emission distribution is 496 SCFM. Additional details are provided in the SI, Section 14.

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similar to the Wilson score interval[25] but applied to a finite population size. The mode of the distribution matches the frequency seen in the field study (2.2%). However, the distribution has a positive skew and a mean of 4.1%; in other words, on average about 1 in 25 facilities is estimated to be a super-emitter at any one time. On each iteration of the Monte Carlo model, the number of facilities simulated as super-emitters is drawn from the frequency distribution in Figure 3. An emissions rate is then drawn for each super-emitter facility from the emissions model shown in the inset of Figure 3 and multiplied by 8,784, the number of hours in 2012. While no one facility may emit at a super-emitter rate for the entire year, the SME assumes that the modeled frequency is representative of the entire T&S sector during any given hour of the year. This method directly represents the uncertainty inherent in observing an infrequent event in a small sample drawn from a larger population.

Comparing to GHGI. The SME includes emission categories that contribute ≈87% of the total emissions in the T&S GHGI. However, sufficient data were not available to estimate emissions from liquefied natural gas (LNG) operations, metering and regulation stations, storage wellheads, pipeline venting, pipeline leaks, and other minor categories (SI, Section 15). In total, the GHGI estimates that these excluded categories emit 266 Gg/yr of methane. These emissions were added, without adjustment, to the SME to estimate the total emissions for the entire T&S sector.

Uncertainty Estimation. Uncertainty was defined empirically as the 2.5% and 97.5% fractiles of each computed distribution to produce a 95% confidence interval (CI). The reported CI includes the impact of variability in the emission and activity models, the frequency uncertainty described for the super-emitter frequency model, and uncertainty in facility count. An additional sensitivity analysis was also performed for transmission station count. The GHGI provides a CI for methane emissions from entire the natural gas system of [+30%/−19%][2] but does not provide a CI for individual sectors, such as T&S. In this study, we apply the overall GHGI CI to the T&S sector on the assumption that uncertainty in T&S is similar to that of entire natural gas system. Since no CI is provided for subsets of the T&S sector, comparisons for individual emissions categories use the mean value reported in the GHGI.

RESULTS AND DISCUSSION

Study Model Estimate. Figure 4 summarizes the predicted methane emissions from the Monte Carlo simulation and comparison to the GHGI and GHGRP. The mean SME is 1,237 Gg/yr [+36%/−23%] for the categories explicitly included in our model. Adding unmodeled categories, total T&S emissions are estimated as 1,503 Gg/yr [+30%/−19%], corresponding to a methane loss rate of 0.35% [0.28% to 0.45%] of the methane transported by the T&S sector in 2012 (based upon 434 Tg of methane contained in a natural gas throughput of 23.8 × 10^{12} scf, SI, Section 16).[26]

On a per station basis, the mean emission rate from compressor stations associated with underground storage facilities (847 Mg/station/yr [+53%/−35%]) is higher than transmission stations (670 Mg/station/yr [+52%/−34%]). Underlying drivers include a higher proportion of engine-driven compressors at storage facilities and a larger number of gas-driven pneumatic devices (see below). Both of these equipment differences result, in part, from operational requirements of underground storage facilities, including the high pressures required for injecting gas into the storage field and additional equipment for processing gas extracted from the field. However, despite lower emissions per station, 75% of SME emissions for the T&S sector are from transmission stations, due to the much larger station count.

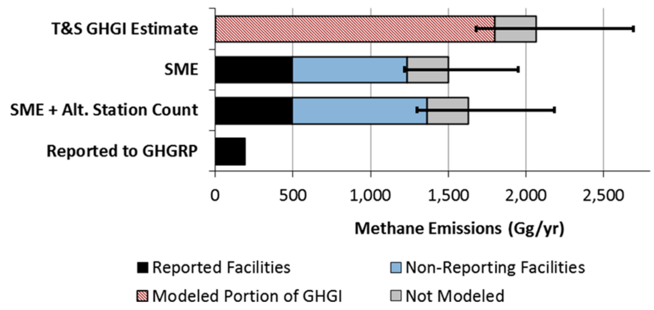

Figure 4. Estimated emissions from the SME for both transmission station count models compared with the 2012 GHGI, including 266 Gg/yr of emissions not modeled in this study ("Not Modeled" bars). Overlapping CI for the GHGI and SME with base station count indicates the two estimates are not statistically different. The GHGI falls within the CI using the alternative station count model, which models 16% more transmission stations and total emissions ≈10% higher than the baseline SME. The bottom bar represents the emissions reported to the GHGRP for T&S facilities, including wellhead components. The SME estimate for the same facilities (495 [+26%/−17%] Gg/yr, the black portions of the SME bars) represents 260% [215% to 330%] of methane emissions reported the GHGRP. In total, emissions reported to the GHGRP (191 Gg/yr) are 15% [11% to 20%] of the SME emissions estimate (1237 Gg/yr) and 11% of the GHGI (1805 Gg/yr) for the modeled emission categories.

Figure 5 breaks down the SME by station and emission type for major emission categories. Figure 6 illustrates the major components of the SME results. Fugitive emissions account for 75% of the total SME, and the balance is from pneumatics, engine exhaust, and station venting. Fugitive emissions are unintended emissions from components such as connectors, valves, meters, compressor equipment (seals, isolation, and blowdown valves, etc.), and similar. The SME breaks fugitive emissions into two parts: First, the SME uses equipment-level emissions, which are characterized using empirical distributions of both emissions and activity data that explicitly accounts for the influence of high emitters on equipment-level emissions. Second, super-emitters are characterized by a separate facility-level model which is independent of all equipment categories.

Approximately 50% of the fugitive emissions are from major compressor equipment, including seal vents, unit isolation and blowdown valves, and rod packing vents (SI, Table S17-a). The next largest category of fugitives is super-emitters, which contribute 39% [24% to 48%] of transmission fugitives and 36% [10% to 54%] of storage station fugitives. Finally, leaks from smaller compressor and noncompressor components (open-ended lines, connectors, etc.) contribute 12−13% of fugitive emissions.

Comparisons between SME and GHGI. Figures 4 and 5 compare the SME to the GHGI estimate for the T&S sector. Considering *only* the source categories explicitly included in our model, the overlapping CI of the SME (1,237 [950 to 1,680] Gg/yr) and the GHGI (1,805 [1,460 to 2,350] Gg/yr) indicate that the difference is not statistically significant. However, this statistical similarity obscures the many significant differences in individual emission categories, often in both activity and

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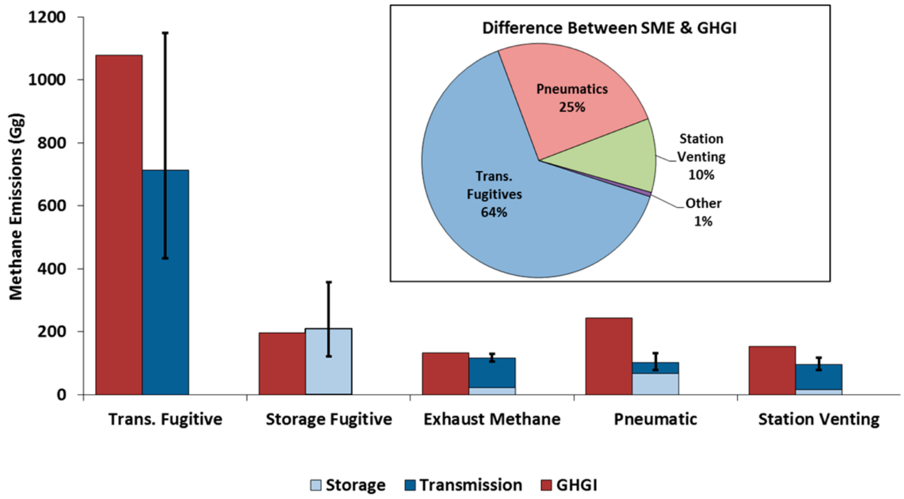

Figure 5. Breakdown of SME into source categories and comparison to the GHGI. Vertical bar chart illustrates the SME divided by major categories, colored by station type, and compared to the GHGI. Black lines represent 95% CI for the SME. The GHGI lies within the CI for three of the five major categories (transmission and storage stations and compressor exhaust) and outside the CI for pneumatic devices and station venting. Inset pie chart summarizes the difference between the SME and GHGI. Two-thirds of the difference originates in transmission fugitives, 25% in pneumatics, and 10% in station venting.

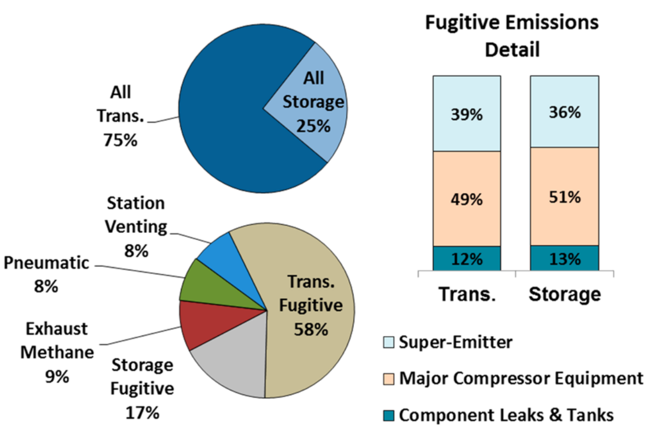

Figure 6. Breakdown of SME emissions by source category. Although emissions per station are higher for storage, 75% of all emissions originate in transmission facilities, due to the much higher station count. Fugitive emissions account for 75% of all emissions. The bar graph further decomposes fugitive emissions. Major compressor equipment, such as isolation and blowdown valve vents and compressor seals, account for approximately 50% of all fugitive emissions, followed by 36–39% modeled at the station level as super-emitters. The remainder is due to other component leaks and tank vents.

emission estimates (SI, Table S17-b). Approximately two-thirds of the difference is in transmission fugitives, followed by 25% for pneumatic devices and 10% in station venting. These differences are driven by three primary factors—the reduced estimate of transmission station count, a significant change in compressor technology mix, and differences in the type and number of gas-driven pneumatic devices. We discuss each of these drivers in turn and then touch on other emission categories.

Station Count. The SME estimates a total of 1,758 [+27%/−19%] stations versus 2,143 in the GHGI (which is based on extrapolation of 1992 data). Controlling for other factors, emissions largely scale with station count, and the reduced station count therefore reduces the overall emissions estimate. Since no complete national data exists for T&S stations, station count was estimated from available data (SI, Section 11). The count of underground storage compressor stations (382 [+9%/−9%]) was estimated from an EIA inventory of underground storage fields[27] and the ratio of storage stations to storage fields for the 72 storage stations operated by the study partners. The GHGI estimates 344 storage stations.

Two approaches were used to estimate the national count of transmission compressor stations. First, a bootstrap method was utilized, based on the transmission stations operated by the study partners and nonpartner facilities reported to the GHGRP. This approach estimates there are 1,375 [+32%/−22%] transmission stations. While the transmission station count is smaller than the GHGI (1,799 stations), the total compressor power of this estimate is very similar to the GHGI estimate due to changes in compressor technology, discussed below. However, since study partner assets are concentrated in the interstate pipeline network, this estimate may not fully account for smaller stations located on intrastate pipeline networks. Therefore, an alternative transmission station count estimate was developed utilizing FERC Form 2 data and scaling by pipeline miles, similar to methods utilized for the GHGI estimate. This method results in a mean estimate of 1,595 [+45%/−25%] transmission stations.

A sensitivity analysis was performed to compare the effect of these two station count estimates on total emissions and is included in Figure 4 as "SME + Alt. Station Count." The alternative estimate of station count is 16% higher than the mean SME estimate. These additional stations are modeled in the SME as smaller facilities similar to nonreporting transmission stations, resulting in a 13% increase in compressor count and a 10% increase in methane emissions to 1,633 Gg/yr [+34%/−21%]. The alternate station emissions estimate corresponds to 76% [57% to 106%] of the mean GHGI estimate for modeled emissions categories and a methane loss rate of 0.38% [0.30% to 0.50%] of methane transported in the T&S sector in 2012. The CI of the SME with the alternative station counts overlaps with both the baseline SME estimate and the GHGI, indicating that differences are not statistically significant.

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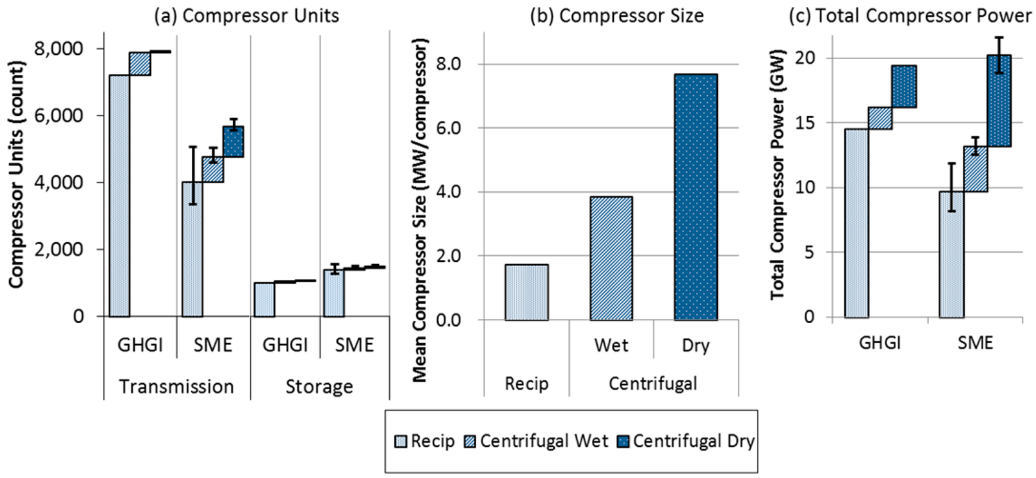

Figure 7. Analysis of compressor technology. (a) The SME, based upon analysis of partner and GHGRP data, indicates substantially more use of centrifugal compressors in transmission (29% [+27%/−19%] of compressors) than the GHGI (9% of compressors). The data also suggest that over 50% of all centrifugal compressors utilize dry seals where the GHGI estimates only 10% dry seals. In contrast, for storage stations, the mix of compressors is similar: GHGI (9% centrifugal) and SME (8% centrifugal). (b) Based upon analysis of partner data, centrifugal compressors, particularly those with dry seals, tend to be significantly larger than reciprocating compressors. (c) The GHGI and the SME (using the base station count estimate) predict similar total compressor power of ≈20 GW. However, the SME indicates that substantially more power is implemented using fewer, larger, centrifugal compressors.

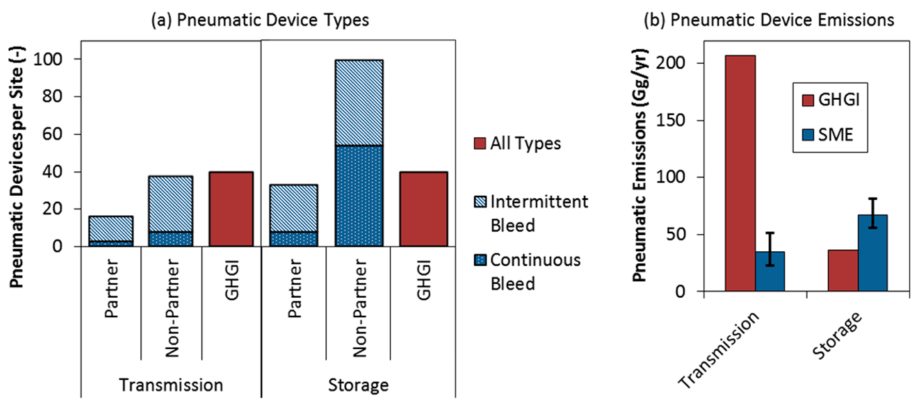

Figure 8. Publicly reported data about partner and nonpartner facilities shows pneumatic devices are unevenly deployed across T&S. Partner facilities utilize substantially fewer gas-driven pneumatic devices. Transmission stations utilize about 33% of the pneumatics per station as storage and a higher proportion of lower-emitting intermittent devices. For transmission stations, SME emissions (35 Gg/yr [+49%/−34%]) are 17% of the GHGI estimate (207 Gg/yr) due to the change in device count, device mix, and a 24% lower station count. For storage, SME emissions (67 Gg/yr [+21%/−18%]) are 190% of the GHGI estimate (36 Gg/yr) due to an increase in devices per station and an 11% larger station count estimate.

Compressor Technology Mix. Partner and GHGRP data indicate a substantial shift in T&S facility configurations relative to the 1992 baseline utilized by the GHGI, with the biggest change in compressor technology for transmission stations. This shift, illustrated in Figure 7, has a substantial impact on methane emissions. Study activity data indicate that 29% [+27%/−19%] of transmission compressors are centrifugal compressors, more than three times the GHGI estimate. Further, study data indicate that over 50% of all centrifugal compressors utilize dry seals, compared with only ≈10% in the GHGI.

The shift in compressor type also influences how compressor capacity is implemented. Detailed descriptions from 461 transmission stations (3,006 compressors) indicate that 96% of centrifugal compressors are powered by combustion turbines or electric drives while 98% of reciprocating compressors are powered by internal combustion (IC) engines. The GHGI does not separately identify electrically driven compressors, which our data indicate represent 9% of transmission and 15% of storage compression capacity. Turbine- and electrically driven units are larger than engine-driven units. Partner data indicate a mean of 5.9 MW/unit for turbines and 9 MW/unit for electric drives versus 1.7 MW/unit for engines. Using average compressor sizes derived from study partner data, the SME predicts a sector total compression capacity of 20.3 GW [+25%/−18%], using the base station count, versus 19.5 GW for the GHGI and (coincidentally) 20.3 GW estimated by scaling FERC Form 2 data, a difference of less than 5% (SI, Section 13). We also predict similar overall compressor usage, (74×10^9 HP · h [+16%/−13%]) compared to the GHGI (69×10^9 HP · h), with similar transmission utilization (102% [90% to 118%] of GHGI) and higher underground storage utilization (156% [124% to 194%] of GHGI). Therefore, our new data reveal a similar aggregate capacity and capacity utilization as the GHGI but suggests a substantial shift in the implementation of that capacity toward fewer, larger, centrifugal compressor units. This shift has two impacts that result in lower emissions: First, methane emissions from turbine exhaust are 2 orders of

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magnitude lower on a per-power basis than engine exhaust. Second, centrifugal compressors with dry seals exhibit approximately 33% less fugitive emissions than either reciprocating compressors or centrifugal compressors with wet seals.

Pneumatic Device Emissions. The SME estimates substantially lower methane emissions from pneumatic devices than the GHGI (42% [32% to 55%] of the GHGI estimate), which accounts for 25% of the total difference between the mean SME and GHGI. Gas-driven pneumatic devices are mechanical actuators operated by compressed natural gas typically drawn from pressurized pipelines. Emissions data from this study indicate an emission rate of 3.5 Mg/device/yr [+13%/−12%] for continuous bleed devices (combining both high and low-bleed types) and uses the GHGRP emission factor of 0.40 Mg/device/yr to model intermittent-bleed devices.

Activity models for the SME are based on pneumatic device counts—a reporting requirement of the GHGRP—from 498 partner and nonpartner facilities reporting to the GHGRP. These data indicate a substantially lower utilization of gas-driven pneumatics in transmission (24 devices/station [+49%/−33%]) compared to storage (85 devices/station [+17%/−15%]). In contrast, the GHGI assumes 39 devices/station at all facilities and does not distinguish between intermittent- and continuous-bleed devices. As indicated in Figure 8, usage of gas pneumatics is uneven across the sector. Partner facilities utilize fewer continuous bleed devices in transmission (2.4 devices/station) compared to nonpartner facilities (7.4 devices/station). The difference in storage facilities was even more pronounced, with nonpartner facilities utilizing 7.3 times as many continuous bleed devices (53.7 versus 7.4 devices/facility). These differences are modeled in the SME (SI, Section 9). Data also indicate a much higher proportion of intermittent-bleed devices in transmission (81% of devices) than in underground storage (51% of devices). These complex interactions lead to three results. First, a lower aggregate emission factor for transmission stations (1.0 Mg/device/yr) than the GHGI; second, lower emissions for transmission (17% [11% to 25%] of the GHGI estimate) due to the combination of fewer stations and fewer devices per station coupled with a larger proportion of intermittent devices; and third, an increase in pneumatic device emissions for storage sites, where the larger device count per station (239% [203% to 279%] of GHGI) more than offsets the decrease in emission factor from 2.7 to 2.1 Mg/device/yr.

Station and Compressor Fugitive Emissions. The treatment of fugitive emissions in the SME differs from that in the GHGI in several respects. First, as described earlier, super-emitters are explicitly modeled as a separate facility-level emissions category. Second, driven by available data and observations from the field measurement campaign, the SME includes all component leaks in station fugitives, whereas the GHGI splits component leaks into compressor- and noncompressor component types. In our model, compressor fugitive emissions are restricted to emissions from major compressor equipment (unit isolation valves, blowdown valves, shaft seals, and rod packing vents).

The GHGI divides centrifugal compressors into two categories by seal type and utilizes emission factors updated in a 2010 ICF study.[19] The underlying emission factors from the ICF study indicate an emission rate from wet seals (48 SCFM/compressor) that is eight times that of dry seals (6 SCFM/compressor), while emission rates measured in this study indicate an emission rate of wet seals (16 SCFM/compressor) approximately three times that of dry seals (5 SCFM/compressor). While this study indicated similar emission rates for dry seals, emission rates for wet seals were significantly lower than utilized for the GHGI (SI, CDFMaster.xls). These results indicate that the emission advantages of dry seals may be overestimated in current literature and may warrant additional study. Annualized emissions are also influenced by the time compressors spend in each operating mode, since seal emissions vary significantly with operating mode. Including these effects, the SME indicates a similar ratio of emissions between wet and dry seal types (1.6 for GHGI versus 1.7 for SME); however, the SME indicates that 22% of emissions for dry-seal compressors are due to seal vents, versus 8% for GHGI.

Compressor Exhaust. Exhaust from both the engines and turbines used to drive compressors contains unburned methane. Methane emission rates in engine exhaust are 2 orders of magnitude higher than in turbine exhaust and therefore dominate exhaust emissions. For engines, the GHGI utilizes an emission factor from the EPA/GRI study of 4.6 g/hp-h. However, total engine emissions are adjusted downward by 124 Gg/yr due to "voluntary reductions," producing a net emission factor of 2.4 g/hp-h (SI, Section 15). The SME derived a completely independent emission factor of 3.7 g/hp-h that is 1.6 times the GHGI emission factor (SI, Table S17-a). Therefore, the voluntary reduction included in the GHGI appears to overestimate actual reductions in exhaust methane emissions.

Station Venting. Station venting includes intentional releases of gas to depressurize equipment, which are also known as "blowdowns." The GHGI estimates station venting using emission factors from the 1996 EPA/GRI study[18] based upon engineering estimates of both the frequency and volume of blowdowns for 15 compressor stations. The SME utilized logged blowdown events from 617 transmission facilities and driven by GHGRP rules, includes all blowdowns larger than 50 ft^3 occurring within station boundaries (SI, Section 4). Based upon these data, the SME estimates lower transmission station venting emissions, 54 Mg/station/yr versus 72 Mg/station/yr, for the GHGI. Since no data were available for underground storage stations, storage stations were modeled using transmission station data weighted by the number of compressors at the facility. This model indicates a smaller emission factor for underground storage stations of 43 Mg/station/yr. As with facility counts, more comprehensive reporting of blowdowns would reduce the uncertainty in these estimates.

Comparison to the GHGRP. Approximately 40% [37% to 43%] of the SME emissions are attributed to the 498 partner and nonpartner facilities that reported to the GHGRP in 2012. These facilities represent 28% of the mean SME facility count for the T&S sector. For this subpopulation of facilities, the SME emissions are 495 Gg/yr [+26%/−17%] versus 191 Gg/yr reported to the GHGRP using GHGRP rules and emission factors (black bars in Figure 4). Three-quarters of the difference between the SME and GHGRP is driven by three emission areas: (a) facility-level super-emitter emissions not included in the GHGRP (33%), (b) methane in engine exhaust estimated using emissions factors based up AP-42 rather than the GHGRP's Subpart C emissions factors (27%), and (c) rod packing vent emissions in not operating, pressurized mode, an emission source omitted from the GHGRP (15%). The remaining difference is due to other sources omitted from the GHGRP, updated emission factors, and differences between

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GHGRP measurement methods and those allowed in the study protocol (SI, Table S18-b).

Due to these factors and the reporting threshold for T&S facilities (25,000 mtCO2e in 2012), the 191 Gg/yr reported under GHGRP represents 15% [11% to 20%] of the 1,237 Gg/yr methane emissions in the SME-modeled portion of the T&S sector. This under-reporting is due to the requirements of the GHGRP rules, not noncompliance by industry.

The GHGRP is a significant new source of greenhouse gas emissions data, covering approximately 25% of T&S facilities, and providing new and valuable activity data, particularly for pneumatic devices, component leaks and compressor equipment, and new emission data in certain reporting categories. However, emissions reported to the GHGRP significantly underestimate emissions from reporting facilities, and need to be interpreted carefully.

Impact of Long Tails in Emissions Distributions. The empirical emissions distributions utilized in the SME allow the impact of long tail emissions to be assessed for fugitive emissions at the component level and for super-emitter emissions at the facility level:

- *Impact of "Long Tail" on Fugitive Emissions*: As illustrated in Figure 2, the "body" of most fugitive emissions distributions represents at least 95% of all measurements (SI, Section 7). These emissions occur in many components and therefore scale with activity levels, such as equipment counts and operating hours, and are characterized by the count and choice of equipment. In contrast, the long tails in Figure 2 indicate emissions that are significantly higher than average are likely in most emission categories and are likely due to equipment or control malfunctions. These emissions, and by extension a substantial proportion of total emissions, would likely be effectively reduced by reducing the frequency at which malfunctions occur and/or reducing the emission rate should a malfunction occur. For 11 of the 17 emission models in Figure 2, the largest 5% of measurements account for 40−75% of measured emissions. Assuming a conservative 40% of emissions in each of these categories could be identified and eliminated, total emissions would be reduced by 14−15%.
- *Impact of Super-Emitters on T&S Emissions*: The paired onsite and tracer measurements made in this study[16] indicate that most emissions may be characterized by comprehensive onsite measurements, but some large facility-level super-emitters are not readily measured by onsite methods. Qualitative observations made during this study indicate that these super-emitter emissions do not scale with equipment counts except at the coarsest level (e.g., facilities) and are better modeled as a frequency of occurrence within a population of facilities. Facility-level super-emitters account for 23% [9 to 39%] of the SME for modeled categories. The model presented here provides a systematic treatment of these emitters. However, the wide uncertainty in the estimate indicates that additional data on both frequency and magnitude would improve national emission estimates.

Together these two forms of skewed emissions distributions account for nearly 40% of the SME emissions. Attention to these emissions categories could have significant impact on overall emissions from the T&S sector.

Considerations for Inventory Development. Although our analysis indicates that the GHGI agrees, within statistical uncertainty, with our estimate of overall emissions from the T&S sector, there are significant differences in a number of key drivers of these emissions. These detailed differences matter if the GHGI is used to assess, for example, the targets and costs of potential emission reduction strategies.[28] Our extensive new data revealed errors in the GHGI activity data (both counts and technology mix) that have an impact on overall emissions similar in magnitude to changes in emission rates, *including* facility-level super-emitters (SI, Table S17-b). Our analysis suggests that a limitation of the GHGI for the T&S sector may not be gaps in understanding emissions but instead what many would consider to be more fundamental, "easy to get" data: counts of facilities and major equipment at those facilities. From an inventory development perspective, one of the most valuable aspects of the GHGRP as it is currently constructed is that it provides this information for the estimated 28% of sites that report to GHGRP. Comprehensive reporting of activity data, including intrastate systems, even if unaccompanied by emissions measurement, would substantially improve inventory completeness and reduce uncertainty.

■ ASSOCIATED CONTENT

Supporting Information

Additional descriptions of the model, emissions models (CDFMaster.xlsx), principal activity models (Activity Models.xlsx), and data input data from study partners and the GHGRP (Input Data Set.xlsx). The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.5b01669.

■ AUTHOR INFORMATION

Corresponding Author

*E-mail: dan.zimmerle@colostate.edu. Phone: 970-581-9945. Address: Energy Institute, Colorado State University, 430 N. College Avenue, Fort Collins, Colorado 80524, United States (Daniel Zimmerle).

Notes

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