Informing methane emissions inventories using facility aerial measurements at midstream natural gas facilities

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Abstract

Increased interest in greenhouse gas (GHG) emissions, including recent legislative action and voluntary programs, has increased attention on quantifying, and ultimately reducing, methane emissions from the natural gas supply chain. While inventories used for public or corporate GHG policies have traditionally utilized bottom-up (BU) methods to estimate emissions, the validity of such inventories has been questioned, increasing interest in utilizing full-facility measurements using airborne, satellite or drone (top-down (TD)) techniques to inform, improve, or validate inventories. This study utilized full-facility estimates from TD techniques to evaluate and improve emissions inventories from 15 midstream natural gas facilities in the U.S.A., and represents one of the first

systematic studies of measurement-informed inventory methods in the midstream supply chain sector. Full-facility estimates were made with two independent TD methods at each facility, and were compared with a contemporaneous daily inventory assembled by the facility operator, employing comprehensive inventory methods. Estimates from the two TD methods statistically agreed in 2 of 28 paired measurements. Operator inventories, which included extensions to capture sources beyond regular inventory requirements and to integrate local measurements, estimated significantly lower emissions than the TD estimates for 40 of 43 paired comparisons. Significant disagreement at most facilities, both between the two TD methods and between the TD estimates and enhanced inventory, indicates that using TD estimates to inform inventories (a) will require additional on site or ground based diagnostic screening and measurement of all sources to improve inventory estimates, and (b) that TD full-facility measurement methods require additional testing, characterization, and potentially improvement, for use in complex midstream facilities.

Introduction

Numerous U.S. domestic and international initiatives[1,2] have increased focus on GHG emissions reductions. In the U.S., the National Climate Task Force has set groundbreaking goals to reduce domestic GHG emissions 50-52% below 2005 levels by 2030.[3] These efforts have focused attention on reducing methane emissions; methane is the second most common greenhouse gas after CO_2, and has a global warming potential (GWP) 86[4] times that of CO_2 on a 20 year basis.

The oil and gas (O&G) supply chain represents a substantial source of methane emissions, notably from the production, transport, and use of natural gas.[5–7] The natural gas supply chain is commonly divided into production, midstream, and distribution sectors; this study considers only facilities in the midstream sector; a related paper discusses similar work in production.[8] Midstream is commonly further divided into gathering and processing (G&P) and transmission and storage (T&S) segments. All of midstream is characterized by facilities that are more complex, and often larger, than production and distribution facilities. Facilities are interconnected by pipelines. While pipelines were surveyed as part of the fieldwork for this study, results are not covered in this paper.

Nearly all midstream facilities include gas compression equipment augmented by inlet and inter-stage separators that remove liquids from gas streams and tanks to store liquids. In many cases, the largest methane emitters from midstream facilities are from compressors and compressor drivers.[5,9,10] Additionally, gas processing plants, and some gathering compressor stations, include additional processing equipment to upgrade gas to pipeline quality, such as dehydrators, acid gas removal units, and associated flares and tanks. Most midstream facilities also include miscellaneous equipment to support pipelines, fuel systems, and similar functions.[11] Finally, storage facilities also include wells and wellhead equipment to store gas in underground reservoirs. This study includes eight transmission compressor stations, five gathering compressor stations, one gas processing plant, and one underground storage facility.

Multiple recent studies have characterized methane emissions[12] from O&G, primarily

focusing on emissions in production basins. Broadly, these studies indicate a tendency for inventories to underestimate emissions relative to facility-scale or regional estimates of emissions.[7,13–19] The persistent disagreement between inventories and measurement-based estimates has placed additional focus on changing traditional inventory methods to improve emission estimates. New regulatory measures that include methane fees, coupled with public commitments by companies to environmental, social and governance (ESG) programs, have also raised pressure on inventories to produce accurate and defensible results.

Recent U.S. legislative action includes the 2022 Inflation Reduction Act (IRA), which funds a number of initiatives to reduce GHG emissions. As with most governmental initiatives, the IRA relies on the inventories as the basis for GHG accounting; for the U.S. these inventories are the U.S. Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP)[20] and the Greenhouse Gas Inventory (GHGI).[5] Both are considered activity-based BU inventories, and have been used as basis for public policy decisions.[21] By 2024, the IRA requires the EPA to revise its GHGRP reporting methods and establish methane emission charges (fees) based on empirical or measurement data that "accurately reflect the total methane emissions." Since it is impractical to measure all emission sources, at all times, these changes will drive the use of infrequent measurements to improve inventory estimates.

One promising approach to improve inventories is to use local measurements to improve the quality of facility-by-facility inventories. For example, a recent study used multiple measurement methods to improve emission inventories in the production segment.[8] These approaches are broadly identified as *measurement informed inventory (MII)* methods. While variations exist between proposed methods,[22–24] all typically include a three-step process:

1. Traditional BU inventory methods (activity counts $\times$ emission factors) and supplemental measurements are used to produce a reference estimate of emissions, the 'operator estimated inventory (OEI)'. In most cases, inventories are improved by comprehensively identifying all possible sources and utilizing per-source measurements, when

available, in place of emission factors.

2. Independent TD estimates are performed using methods that estimate full-facility emissions (either directly or by estimating and summing emissions from major sources). Since these methods have limitations, including method detection limits (MDLs) that vary with environmental conditions, TD estimates do not necessarily capture all emissions from a facility. Therefore, TD estimates are often supplemented with other information, such as per-source measurements and/or estimates using established BU emission factors, to produce a complete estimate of emissions, or an *adjusted* TD estimate.

3. The OEI and TD estimates are aligned to the same time basis and compared to assess inventory completeness and inform changes to improve inventory results.

In this work we will examine these three steps by focusing on the time period when measurements underlying the TD estimates were conducted - typically one working day (the time basis in step 3, above). This represents a subset of a complete MII process, which must also account for source intermittency and episodic events, like blowdowns or upset conditions, changes in operational state of facilities, etc. By focusing on the measurement period, TD and BU methods can be compared with minimal complications, highlighting how information can be exchanged between these methods to improve emissions estimates.

While theoretically estimating the same emissions, fundamental differences between TD and OEI methods complicate comparisons for midstream assets. Three key differences need to be considered:

First, the TD methods typically measure over short time periods – seconds to a few hours. In contrast, OEI methods sum a set of point-source estimates, which are inherently based upon observations made over different time frames - from hourly logs of operating conditions to short-duration point-measurements of individual sources. The inherent averaging in inventory methods works well for long-duration (typically annual) emissions, but may not

capture the specific conditions when TD methods were sampling.

Second, OEI methods rely on emission factors when measurements cannot be made. These factors typically originate from prior field studies conducted years earlier on facilities operated by multiple O&G operators. While well-performed studies include the full range of emissions from each source category, emission distributions are inherently averages across facility types, operating methods, failure modes, etc. Further, inventories use only the mean emission factor, and therefore do not account for extremes in emission rate which may exist on any one facility.

Third, unlike production and distribution sectors, midstream facilities frequently change *operational state* – primarily by starting, stopping or changing load on compressors or processing equipment. These state changes drive substantial variation in emissions from the facility.[25] For example, a mid-sized gathering compressor station could see methane emissions vary by 350% due solely to compressors changing operating mode (SI Section S-3.3). State changes may also occur frequently, often multiple times per day.

Finally, the work conducted for this study was part of a larger Quantification, Monitoring, Reporting and Verification (QMRV) program. The QMRV research and development (R&D) program includes modules for all sectors of the natural gas supply chain, and[26] each module defines three phases:

- A **baseline phase** resulting in an TD-OEI comparison, as described above.
- An **enhanced monitoring phase**, where operators monitor emissions, estimate/update monthly OEIs, and monthly MIIs's are computed.
- An end-of-project **verification phase** when another TD-OEI facility comparison is done, and final MII analysis is completed.

The study was conducted at 15 facilities, dispersed across four U.S. states, and operated by six midstream companies. At the time of writing, all facilities are in the enhanced monitoring phase; this paper analyzes results from the completed baseline phase.

Methods

All facilities in this study were measured *as found*, during a pre-planned measurement period, typically a day in length. Facilities were operated as if measurements were not occurring, with the measurement teams working around any on-site activities, including maintenance work and operational changes.

Reconciliation is a process whereby the TD estimates are compared to the OEI. This requires three methodological elements: Characterizing the TD measurement methods, estimating uncertainty, and adjusting TD estimates to fully estimate facility emissions.

Measurement Methods

Bridger Photonics Gas Mapping LIDAR (GML) (Solution 1) and SeekOps flux-plane mass balance drone (Solution 2) were contracted to provide TD estimates at all facilities.

Solution 1[27] utilizes a downward looking laser system that sweeps perpendicularly across the direction of flight of an aircraft, and uses differential absorption to compute path-integrated methane concentration (ppm-m) from the aircraft to the ground. This system can detect concentrated (point source) emissions that produce sufficient imaging contrast to separate the emissions plume from background methane concentrations. Solution 1 utilizes wind data to compute an emission rate from the plume image (i.e. 2-dimensional concentration map) and wind speed; meteorological data is obtained from nearby weather station(s) without installing an anemometer on the facility. Solution 1 also collects visual imagery and superimposes plume data on the photos to provide context for the detections.

In this study, Solution 1 typically screened (hereafter termed an 'overflight') each facility twice during one day, typically making multiple passes to complete each overflight. Each facility overflight takes less than an hour, while individual plumes are scanned in a few seconds. Since each overflight has multiple passes, an individual emitter may be characterized by several plumes if the emissions appear in more than one pass. Therefore, the estimated

facility emissions for Solution 1 are the result of adding results from multiple distinct plumes into one overflight estimate. In this study, each overflight, typically separated by several hours, is treated as an independent estimate.

Solution 2[28] uses a flux plane method with concentration data from miniature, tunable-laser spectroscopy sensor on a drone platform. The flux plane methodology is thoroughly discussed in literature.[29,30] Briefly, the drone-mounted sensor measures methane concentration while making multiple downwind passes through the facility's emission plume at different heights, typically from near ground level to above and outside the plume – i.e., above any methane enhancements from the equipment being measured. Concentration measurements, multiplied by the normal of the wind speed through the plane of flight, are integrated across the flight plane to calculate an emission rate.

Solution 2 deploys a ground meteorological station to collect wind speed data, and also extracts wind data from directional corrections applied to the drone while in flight. Solution 2 typically flies multiple flight planes within the facility to estimate emissions from subsets of equipment; the total facility estimate is the sum of all subsets. While each flux plane is completed in 20-40 minutes, it takes several hours to collect a full-facility estimate when measuring multiple subsets of the facility.

Solution Uncertainty

Both TD methods utilize proprietary algorithms to translate measurements from onboard instruments into emissions estimates. Uncertainty of each estimate is a function of multiple input uncertainties, ranging from instrument uncertainty (typically small) to larger wind field and algorithmic uncertainties. Therefore, this study uses uncertainty estimates from controlled testing of the integrated solution.

Bell et al.[31] performed controlled testing with Solution 1 to assess the quantification accuracy and detection limits. The dataset included 650 individual measurement passes. One known emission source was used, while the emission rate and timing of the controlled

releases were unknown to Solution 1. The study found Solution 1 to have a 90% probability of detecting emissions over 1 kg/h when deployed on a fixed-wing aircraft. The Bell et al. dataset was used to produce two uncertainty models for two bins of controlled release rates (0 to 10 kg/h and 10 - 2500 kg/h), resulting in an empirical distribution of relative errors for each bin. (SI section S-2.3)

For Solution 2, this study uses data from Corbett et al.,[29] a single point controlled release study with releases from an elevated platform. The dataset included 12 non-zero tests. Comparable to the Solution 1 testing, the release location was known, but the rate of the controlled release was blind. Data were used to develop a single empirical relative uncertainty model that was applied to all estimates. (SI Section S-2.5)

When Solution 2 subdivides the facility to create partial-facility estimates, analysts may subtract an emission estimate from one flux plane estimate from another flux plane estimate to account for upwind emissions. Subtraction impacts uncertainty of the estimates. Since reports from the vendor do not indicate when subtraction was used, uncertainty was not adjusted for this impact.

Both methods are dependent on environmental and atmospheric conditions. The controlled testing used single point sources in known locations that had less complex configurations than at midstream facilities, which have multiple, potentially overlapping and/or intermittent, emission sources and large structures that produce complex near-field winds. Each method has weather-dependent detection and quantification limits. Additionally, each method has specific challenges. For example, methane in compressor driver exhaust ('methane slip') may be too dilute to be visible to Solution 1's imaging or emissions may pool or recirculate near large compressor buildings, possibly complicating or distorting either solution's quantification estimates. Therefore, the uncertainty models used here should be considered minimum estimates of uncertainty; in field conditions, uncertainty is likely larger.

Finally, the methods differ on how brief, small, emission events (e.g. intermittent gas releases from pneumatic controllers) are quantified. Timing of these events is unknown.

Assuming random timing, some portion of these emissions will be transported by the wind and increase methane concentrations seen by the Solution 2 sensor, increasing Solution 2 estimates. The impact is unknown; in this study we assume these emissions are sufficiently random and mixed that Solution 2 detects CH_4 enhancements that are representative of mean emissions from these sources. In contrast, these emission events create insufficient plumes to be detected during a Solution 1 overflight, and have minimal impact on Solution 1 estimates. Therefore, to compare the two solutions, we add an estimate of these emissions to Solution 1.

In contrast, large episodic emissions, such as compressor unit blowdowns (depressurization of a compressor), can be identified by onsite observers. Since neither method can accurately estimate emissions from these events, estimates made during during large episodic events are discarded, see SI Section S-3.1.

Aligning TD and OEI estimates

A series of adjustments is required to bring the OEI and TD estimates to the same temporal basis and to accommodate differences in detected emitters.

OEI methods estimate emissions by identifying emission sources, and estimating emissions by one of two methods: (1) estimating activity data for each source and multiplying by an appropriate emission factor (e.g. pneumatic controller emissions), or, (2) using a source-level on-site measurement (e.g. component leaks). Sources were either known (e.g. compressor vents, blowdown stacks, etc.) or are discovered via leak surveys; optical gas imaging (OGI) surveys and a Hi-Flow sampler were used in this project. In this study, source-level measurements were made where possible (SI Section S-1); other emitters were estimated using emission factors. OGI surveys were conducted throughout the day, and (with the exception of the compressor-dependent emitters discussed below), all emitters were assumed to emit at a constant rate throughout the measurement period.

As noted earlier, a change in operating state of the facility may change emissions significantly. In principal, 'operating state' of a facility is difficult to define, as emissions may be

impacted by which compressor or processing units are online, the load on units, changes to process settings, changes in cycled or throttled valves, and numerous other factors. However, prior studies have indicated that emissions driven directly by the operating state of compressor units often dominate overall emissions from midstream facilities.[9,10] Therefore, compressor operating state provides a useful surrogate for the facility state at midstream facilities.

To align estimates, three steps were taken. First, operators were requested to calculate OEI estimates so that individual operating states could be extracted from the estimate. Operators also provided a log of when compressor units were operating and/or pressurized. This allowed the OEI to be decomposed into one OEI estimate for each operating state. Note that OEI estimates are assumed constant for each operating state; this effectively averages estimates for variable emitters (e.g. intermittent pneumatics or dump valves on compressor interstage separators).

Second, an independent observer from the study team noted compressor states and the time of large episodic emissions, such as blowdowns, compressor starts, etc. While episodic emissions need to be tracked and included in long-duration emissions totals, comparisons performed here exclude episodic events from OEI estimates. TD estimates made during these episodic events were eliminated from resulting comparisons. This simplification has no impact on TD-OEI comparisons; TD methods cannot reliably measure episodic events, and the same engineering calculations would be used to estimate these emissions for both OEI and TD estimates.

Third, TD estimates were compared to OEI estimates in the same compressor operating state. For Solution 1 overflights, comparable states were identifiable. Solution 2 measured over longer periods, increasing the likelihood that operating state would change during measurements. This type of impact was seen at 3 of 15 facilities. Since operating state changes may have created substantial variations in emissions, the comparison weighted the OEI estimates by the time in each state over the measurement period (SI Section S-2.6). Using a

weighted average OEI effectively assumes that Solution 2's total estimate effectively averages emissions similarly to the weighted average OEI. The validity of this assumption is impossible to test. It is also indicative of the challenges of comparing TD estimates to complex, time-averaged, OEIs in any MII program.

In addition to temporal alignment, estimates need to be adjusted to represent, but not double-count, all emissions from the facility. Adjustments are method-specific. For example, Solution 1's method typically omits emitters below the method's MDL; these need to be added to the Solution 1 estimate. Additionally, quality review indicated that Solution 1 did not consistently detect and quantify methane in compressor driver exhaust (compare SI Figure S-2 versus S-3). An expert panel was utilized to estimate whether Solution 1's estimate included combustion slip (SI Section S-2.2). Results indicated that Solution 1 detected exhaust plumes at 3 of 8 facilities where substantial combustion slip would be expected due to the type and size of compressor drivers on the facility. If Solution 1 did not detect exhaust at a facility, emissions from combustion slip were estimated using recent stack tests, if available, or emission factors if not.

In general, Solution 2 captures emissions from all emitters upwind of the flux plane that were active within the transport time of the emissions. However, exceptions exist for flights that did not extend high enough to traverse exhaust plumes from compressor drivers (Facility C). Since the drone transects are fast, additional uncertainty exists for unsteady emission sources near the flux plane (e.g. intermittent gas pneumatics) or in cases where wind near a building may attenuate or recirculate emissions. Unfortunately, no data exists to characterize these uncertainties. Finally, as noted earlier, multiple flux planes within one facility require adjustments by Solution 2's analysts to avoid double-counting emissions. In this study we assume these corrections were perfect, and no emissions were transported through two flux planes without correction. (SI Section S-2.4)

The adjustment process outlined here is typical of TD adjustments required for MII methods to construct complete estimates of emissions.

Calculating the measurement emissions check (MEC)

After the TD methods were adjusted to represent a full-facility estimate, all independent estimates were averaged to produce the MEC – typically one Solution 2 estimate and two *adjusted* Solution 1 estimates for each facility, with the exceptions noted in SI Section S-3.1. In this analysis, the MEC is used exclusively as an unbiased estimate of facility emissions for plotting and normalization, and is not directly compared to the OEI or either TD method.

Results & Discussion

Results are presented as a series of full-facility emission comparisons, with all independent estimates brought to a comparable basis as described in *Methods*. For these comparisons, *adjusted* Solution 1 and Solution 2 estimates are used, compared to each other and to the OEI. In the following discussion, the reader should assume that any mention of Solution 1 refers to the *adjusted* estimate.

Solution Comparison

While most MII efforts would deploy only one TD method, this study had access to two TD technologies to support additional analysis. The flux-plane and LIDAR methods selected for the study both create facility estimates, but use distinctly different measurement instruments and analysis algorithms. Since both were deployed contemporaneously (same day in most cases), these estimates can be compared to better inform the uncertainty of both methods.

Figure 1 uses a Bland-Altman difference plot to compare the two TD estimates. This analysis plots relative difference between two estimates against a common estimate of emission rate. The facility MEC was used for both the X axis and as an average estimate normalize relative differences. Each point represents one estimate at one facility. Error bars indicate a 95% confidence interval for each estimate; see SI Section S-2.3 and S-2.5. For each facility, there are two independent Solution 1 estimates, completed at different times,

which generally appear as points immediately above each other. Each estimate comparable to Solution 2. Relevant means are listed in Table 1.

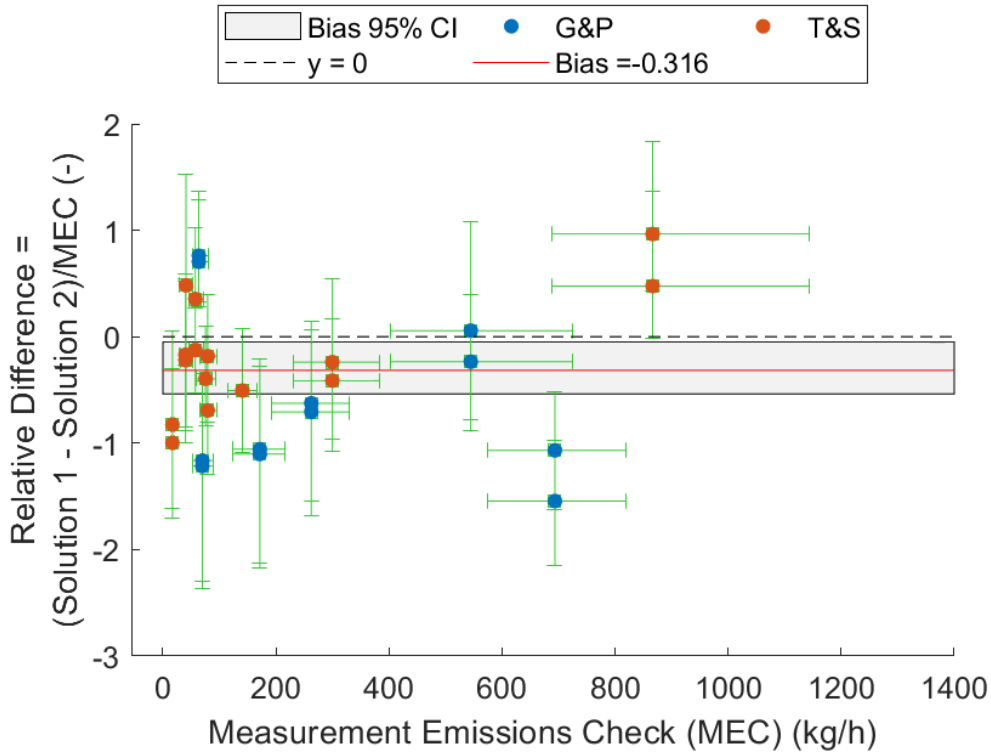


Figure 1: The horizontal axis is the MEC, the vertical axis is the relative difference between the *adjusted* Solution 1 and Solution 2 estimates for each facility. The gray box displays the 95% confidence interval over all facilities. The dashed line (y = 0) displays perfect agreement.

Table 1: Aggregate Emissions over 15 Facilities (kg/h)

	TD Method		
OEI	*Adjusted* Solution 1	Solution 2	MEC
696	3,000 [2,670 to 3,495]	4,057 [3,688 to 4,361]	3,422 [3,102 to 3,806]

See SI Table S-3 and S-4 for emissions by individual facilities.

In aggregate across all facilities (gray box in figure), *adjusted* Solution 1 estimated emissions were 1,073 [387 to 1,586] kg/h lower than Solution 2, a statistically significant difference of 31% [12% to 47%]. For pairwise comparisons at individual facilities, the two TD estimates statistically agree in 2 of 28 comparisons (Kolmogrov-Smirnov 2-sided, $\alpha = 0.05$),

with Solution 1 reporting emissions that were statistically lower than Solution 2 in 20 comparisons and higher in 6 comparisons. Results are compared using other methods in the SI Section S-3.2.

Method disagreement could be compounded by changing operating states during measurement. Eliminating the 3 facilities where the operating state changed during measurement increased the fraction of comparisons that agree by ≈3%, from 2 of 28 to 2 of 20, and decreased the fraction of comparisons that disagree by a similar amount; this is likely not a significant source of disagreement between methods.

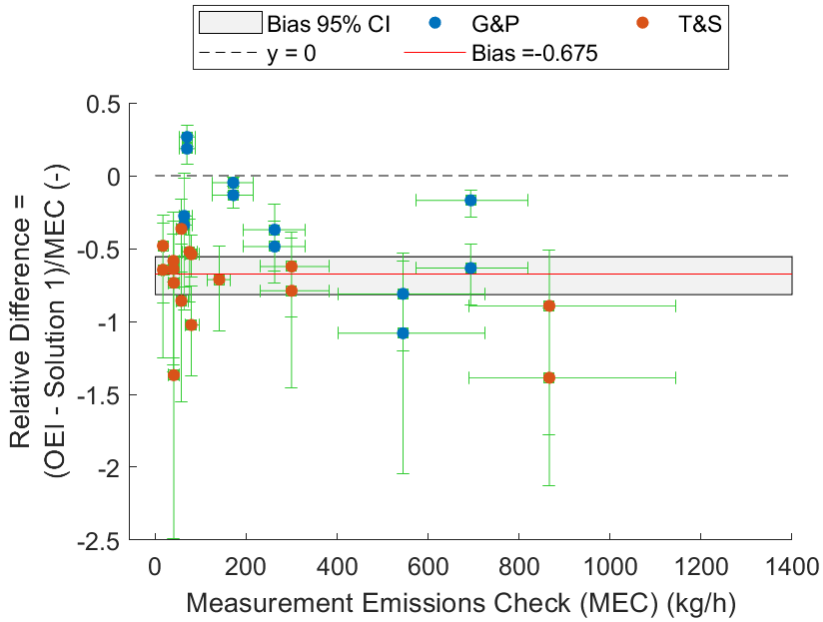
While emissions *could* change while the facility is in one operating state, operational knowledge indicates that large changes were unlikely. Therefore, since both methods measured when emissions were essentially stable, it is likely that the TD methods, in field conditions at midstream facilities, have uncertainties larger than indicated by controlled testing, likely due to multiple emission sources and complex wind fields at these facilities.

The above analysis of TD method uncertainty impacts the confidence in the TD estimation component of MII methods, and offers guidance for calculating these results. Outside an R&D program, most MII programs would utilize only one TD estimate at a time. Therefore, uncertainty in the TD estimate would be inherently difficult to assess using one estimate at each facility. Inventories could be in or out of agreement with TD estimates due solely to uncharacterized uncertainty in the chosen TD method. Further, most reporting programs report only mean values without uncertainty, and have no systematic method to capture uncertainty. Taking the current study as a test case, had all 15 facilities been part of a single report, the aggregate uncertainty in the TD methods, without reference to any inventory methods, would be at least 31% – the difference in the mean estimate of total emissions between the two TD methods.

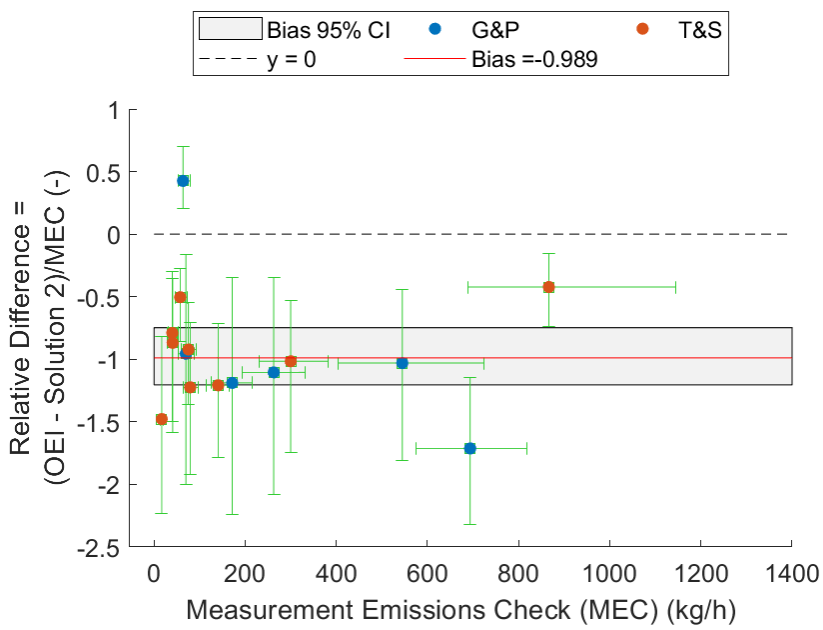
These results indicate a need for better controlled release and field testing of these methods at complex facilities to better characterize TD method uncertainties, and a need for MII protocols to consider further assessment and reporting of TD uncertainty.

OEI Solution Comparison

The second analysis of importance is the comparison between the OEI – i.e. the BU inventory – and TD estimates for each facility and for all facilities aggregated together. This comparison uses the adjusted full-facility estimate from each TD method, compared to the calculated OEI. Figure 2 illustrates the difference between the OEI and the TD estimates, using the same plot format as Figure 1.



(a) Comparison OEI to *adjusted* Solution 1. Where two points are vertically aligned, each represents a Solution 1 overflight, typically two per facility.



(b) Comparison OEI to Solution 2

Figure 2: Comparison of the BU inventory (OEI) to each of the two TD methods, Panel (a) for *adjusted* Solution 1 and Panel (b) for Solution 2. An average of TD estimates, the measurement emission check, is used for both the horizontal axis and normalization; see text. The vertical axis is the relative difference between the OEI and adjusted TD measurement for each facility. The gray box displays the 95% confidence interval over all facilities. The dashed line (y = 0) displays perfect agreement. For both TD methods, the OEI is statistically lower over all facilities, and on a per-facility basis the mean is statistically lower at in all but three cases.

When comparing OEI to TD methods, it is important to note that OEI estimates have no stated uncertainty. Therefore, uncertainty in all comparisons is exclusively from the uncertainty estimate of the TD method. For both TD methods, the operator's inventory is significantly lower than either of the TD methods at the vast majority of facilities; the OEI is statistically higher than Solution 2 in 1 of 15 comparisons, and statistically higher than Solution 1 in 2 of 28 comparisons. Although TD estimates may have higher uncertainty than shown, logical increases in uncertainty are unlikely to close the gap between the TD and OEI estimates.

An OEI was estimated for each of the 15 facilities using traditional inventory methods augmented with supplemental sources, emission factors from recent studies, and other modifications to assure the inventory captured all known sources (see QMRV protocol[32] in the SI). The protocol also augmented routine emission factors with direct measurements for significant sources. For example, stack tests were used to directly measure methane slip in combustion exhaust, in an as-found conditions. Therefore, the OEI process used in this study is among the most robust used in any program. Given the diversity of reporters and facility types, the significant disagreement between BU inventories and TD estimates indicates systematic under reporting in the OEI and/or issues in the TD measurement. Disagreements are neither company-specific nor facility-type specific.

The intent of the MII process is to utilize measurement-based estimates to improve the inventory process for a specific facility (or small group of facilities) over results using traditional inventory methods. If successful, the improved inventory process would then be used to accurately estimate emissions for each of the facilities' operating states, over extended periods – the result needed for regulatory reporting, voluntary initiatives, and similar purposes. The question then, is how *do* TD measurements inform inventories? In this study, the TD/BU disagreement could originate from three potential causes (or any combination of the three):

1. *Known sources are systematically underestimated in BU inventories.* A small number of well-known sources are known to dominate midstream facility emissions (e.g. leakage through large valves, venting from compressor seals, etc.)[9,10,33] All such sources are included in the QMRV OEI calculation, using on-site measurements wherever possible, or best-in-class emission factors when measurement was not possible. Therefore, for known sources to drive the TD/BU disagreement, both measurements and/or emission factors for a large number of key midstream sources would need to be systematically underestimated relative to common field conditions.

   While there is little evidence for systematic low bias, it cannot be ruled out. Some sources at facilities are difficult to measure, due to the size of equipment (e.g. a large diameter blowdown stack), accessibility of an emission location, safety issues, or due to variability in emission rate. For on-site measurements, the largest emitters often prove the hardest to measure.[10] Systematic errors in these measurements are possible, and could contribute to the TD/BU disagreement. Additional on-site measurements and/or continuous metering of some sources may be required to characterize major emission sources across multiple operating states.

2. *Un-inventoried, large, emission sources exist on many facilities.* One emitter of this type was discovered on one facility during TD measurements (a leak in a fuel gas

system, included in data presented here and corrected the day after identification). No similar large sources were found on the other 14 facilities. Therefore, *if* large emitters were to explain the gap to TD estimates, multiple such sources must exist on most facilities *and* these sources must have unknown characteristics that made them undetectable by Solution 1 overflights. While there is no evidence for this type of large, systematic, emission source on midstream facilities, it cannot be ruled out. Per-source screening and measurements would likely be required to either identify these sources or increase confidence that they do not exist.

3. *TD estimates are biased high, and this bias is systematic for this type of facility.* As with the other potential causes, there is little evidence of systematic high bias in TD methods, in part because these methods have not been extensively tested on complex facilities like compressor stations under controlled conditions. Current controlled testing was performed at near-ideal conditions - single source, no nearby structures, etc. Winds may recirculate emissions near large structures (where both TD methods estimate emissions), or multiple nearby emission sources may complicate rate recovery algorithms.

Given the size of the TD/OEI disagreement, all three of the above causes deserve evaluation. The above analysis indicates that, for midstream facilities, an 'informed' inventory will likely require a more comprehensive program than simply performing periodic TD measurements at a facility; full-facility estimates need to be augmented with additional, on-site, diagnostic work and measurements. For example, many vents or other sources on midstream facilities could be metered and monitored over extended periods, and compared to TD estimates.

Extending to Long-Duration Estimates

The ultimate goal of the MII is to establish total facility emissions over extended periods; monthly or annual estimates are common. All analysis above considers the simplified case where (nearly) contemporaneous TD estimates were compared to an OEI estimate made for the facility. This comparison was typically limited to emissions measured in a single operating state, and even when operating state changed during the day (3 facilities), full estimates in each state were not possible. Emissions in operating states that were not active during measurements were not characterized by TD estimates or measured by onsite methods. For example, a single compressor unit may be operating, pressurized not operating, or depressurized. In each mode, different valves are open and shaft or rod packing seals operate differently. Considering only compressors at a typical station, emissions may vary by 2.5-3.5 times due *solely* to changes in operating mode (SI Section S-3.3). Large swings in emissions due to operating state changes are less common in production and distribution operations. Therefore process analyses from other sectors may not translate directly to midstream operations.

As a result of state changes, MII methods must estimate emissions from operating conditions which were inactive during TD surveys or design TD surveys to better study the facility in *all* operating conditions. This implies that single snap-shot TD estimates are unlikely to replace annual BU inventory methods for midstream facilities until additional testing is completed, and that midstream will require high-quality logging of operating state, per-unit and per-source emission factors and/or per-source measurements for the foreseeable future. This can be in the form of advanced monitoring and tracking systems of a facility's operational states, supplemented by identifying, measuring and including any unplanned emissions.

Implications

Inventories are an important tool for making policy and industrial decisions, and there needs to be confidence that these inventories are accurate. MII methods suggest that inventories can be verified by TD estimates that capture all emissions at a facility.[34] Results from this study confirm this reconciliation may be possible, but indicate several nuances that must be considered when using TD estimates to verify inventories at midstream facilities. First, for the diverse set of facilities considered here, a simple comparison of TD estimates to a contemporaneous BU inventory yields the unsatisfying result that these estimates disagree, with little guidance on how to eliminate the disagreement. Therefore, measurement informed inventories will likely require both full-facility, TD estimates *and* a battery of diagnostic measurements or monitoring on-site – both to identify causes of disagreement between TD and BU estimates made in the same operating state and to capture operating states not included in the TD estimates.

Second, in this study, the TD/BU disagreement is systematic – at 40 of 43 TD-OEI comparisons, TD method is statistically higher than the contemporaneous inventory. For midstream there is no ready explanation of *why* this disagreement exists. While per-source measurement at facilities may under-report emissions due to challenges mentioned earlier, it is unlikely that these issues would explain the TD/BU disagreements seen in the study - at 35 of 43 comparisons, there is a disagreement of more than 2X. All known large sources are included in the enhanced inventory process used here, and additional large sources were not identified by the source-locating TD method (Solution 1) in sufficient quantity and size to account for the difference. Therefore, results of this study indicate the need for more extensive on-site identification and measurement of midstream sources, coupled with better characterization of TD method uncertainty for midstream facilities.

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Competing Interests

F.C.G., G.R. and S.R.W. are employees of Cheniere Energy Inc. D.Z. has current research support from multiple natural gas operators, Cheniere, Department of Energy, and has worked as a consultant for SLR International in recent years. SLR International performs work for Cheniere, other oil and gas industry clients, academic institutions, and industry research organizations.

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Supporting Information Available

The following files are available free of charge.

- QMRV Protocol: Document that was provided to operators to complete the QMRV R&D objectives (PDF)
- Emissions Calculation Guidance Tool: Contains improved calculation methodology for emission sources (xlsx)
- Supporting information: Contains additional details on facilities, solution methods and uncertainty, state simulation.

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TOC Graphic