

Article

Calculating Methane Emissions from Offshore Facilities Using Bottom-Up Methods

Stuart N. Riddick ^{1,2,*} , Mercy Mbua ² , Catherine Laughery ² and Daniel J. Zimmerle ² ¹ Department of Science, Engineering and Aviation, University of the Highlands and Islands Perth, Crieff Road, Perth PH1 2NX, UK² Methane Emission Technology Evaluation Center (METEC), Energy Institute, Colorado State University, Fort Collins, CO 80524, USA; mercy.mbua@colostate.edu (M.M.); kate.laughery@colostate.edu (C.L.); dan.zimmerle@colostate.edu (D.J.Z.)

* Correspondence: stuart.riddick.perth@uhi.ac.uk

Abstract

With changing demands in regulation, understanding methane emissions from offshore oil and gas production infrastructure has become increasingly important. Reported emissions from facilities in the Gulf of Mexico range from zero to thousands of tons of methane per hour, but there is currently no clear understanding of how this range compares to expected emissions from normally operating facilities. To generate realistic emission estimates, we create two bottom-up models that simulate emissions from facilities operating in the Gulf of Mexico. We estimate type 1 prototypical facilities (typically unmanned, older, lower-producing platforms in shallow water with little processing equipment, compressors, or storage tanks) to emit an average of 13 kg CH₄ h^{−1}, which corresponds to a loss of 2.7% of the average facility production. Type 2 prototypical facilities (continuously manned, higher production and operate in deeper water with processing equipment, oil storage tanks, compressors and power generation) emit an average of 88 kg CH₄ h^{−1}, which corresponds to a loss of 2.5% of production. The average measured emission from type 1 facilities was 18 kg CH₄ h^{−1} with a median production loss estimated at 8%. The average measured emission from type 2 facilities was 36 kg CH₄ h^{−1} with a median production loss estimated at 2.4%. Using emission factors that consider the long-tail emission distribution partly reconciles the difference between modelled and measured emission estimates, but we suggest the current fugitive emission estimate may be an underestimate and more data on the number and size of fugitive emissions could explain differences between the modelled and measured emission estimate. We suggest the bottom-up approach described here that uses production data coupled with facility equipment could be used to identify facilities that have abnormally large measured emissions, caused by methodological failure or larger than expected fugitive emissions, which should be targeted for further evaluation resulting in remeasurement or identification of source type so that a more accurate estimates can be made on the absolute emission.

Keywords: bottom-up; methane; emission; offshore; production facility; oil and gas

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1. Introduction

Recently, companies with offshore assets are joining international oil and gas reporting frameworks such as the Oil and Gas Methane Partnership (OGMP) 2.0 [1]. OGMP 2.0 member companies target Level 5 reporting (detailed source-level and site-level measurements

reconciliation) with benefits such informing methane mitigation opportunities, preparedness for regulations such as the European Union regulation that require external oil and gas producers to report emissions in line with OGMP2.0 Level 5 reporting, reducing revenue loss from wasted methane (leaks), and for market and finance access such as the World Bank's Global Flaring and Methane Reduction Framework [1]. Similar measurement-based reporting frameworks such as the QMRV (quantification, monitoring, reporting and verification) [2] have emphasized the need for supplementing bottom-up inventories with specific facility measurements to inform methane mitigation and intensity targets. This means that offshore companies are facing similar needs and pressure as onshore companies to accurately report their emissions to adhere to regulatory and market requirements.

With an increase in methane reporting requirements and recent developments in technology (satellite, aircraft, drones), quantification of methane emissions from offshore oil and gas production infrastructure has become more important and studies reporting emissions more numerous. While reported emissions range from those below method quantification limits (i.e., negligible) to thousands of tons of methane per hour, there is currently no clear understanding on what "expected" emission from offshore facilities should be or what is the likely magnitude of emissions from expected vented events or upset conditions. Here, expected vented event emissions are typically short-lived maintenance events, i.e., result from the sub-60 s depressurization (or 'blow-down') of a high-pressure gas containing vessel, and upset conditions are longer-term emissions from either fugitives or a result of remediating a safety concern, e.g., where the repair of an export pipeline results in the flaring of all produced gas. Regulations stipulate that operators should record maintenance events and emissions resulting from safety concerns with likely emission rates calculated; therefore, the emissions that are 'unknown' are those that arise from equipment on the facility or from fugitives.

An understanding of how large methane emissions from oil and gas production infrastructure can be derived using bottom-up modelling. This approach typically generates a total emission by summing the emissions from all individual sources, and individual source emissions are calculated by multiplying an emission factor (usually mass of methane per source per unit time) by the number of sources. One example of bottom-up modelling is the monthly emissions inventory generated by the US Bureau of Ocean Energy Management (BOEM) for all offshore platforms in the Gulf of Mexico [3]. Annual BOEM inventories are generated every three years with the latest in 2017 and have been used to by another study to investigate the effect of intermittency on facility emissions profiles [4]. Another study generated a bottom-up emissions inventory using emission factors and production data to estimate methane emissions from oil and gas production facilities in the North Sea at 0.72% of production [5], with 0.19% lost through "expected" production/processing activities. Currently there is no available methane emissions data that has been generated using contemporaneous production data and an understanding of equipment on each offshore production platform.

In recent years, fourteen studies [6–18] have used five quantification methods (downwind dispersion, mass balance, tracer flux, aircraft remote sensing, and satellite remote sensing) to measure emissions from 458 facilities in the Gulf of Mexico, the North Sea, Malaysia, Borneo, Canada, and East Africa. Focusing on the Gulf of Mexico, where the majority of measurements have taken place (323 facilities) and where the most is known about the production rates, the average facility emissions are estimated at $658 \text{ kg CH}_4 \text{ h}^{-1}$, which corresponds to $835 \text{ Mscf CH}_4 \text{ day}^{-1}$ [19]. This emission estimate is very much larger than a bottom-up emission estimate for a typical offshore facility in the North Sea of $83 \text{ kg CH}_4 \text{ h}^{-1}$, which includes emissions from combustion (generators, export compressors) and processing (flash from the oil tanks, dehydrators and water treatment) activities [5].

Justification for the emission rates has been presented in individual publications and has been attributed to flaring of all produced gas during export pipeline repairs, venting of methane from storage tanks and the result of poor maintenance coupled with hurricane storm damage. What is currently unclear is whether these reasons can rationally justify the emission rates calculated. To investigate if current methods generate realistic emission estimates, we will create bottom-up models that simulate prototypical facilities operating in the Gulf of Mexico and compare the calculated emissions to actual emissions reported by published studies. Specifically, we aim to 1. Create bottom-up emission models that simulate facilities operating in the Gulf of Mexico; 2. Compare the expected emissions to actual emissions reported by published studies; 3. Identify if the any discrepancy is real, i.e., within the reasonable expectations of a fugitive emissions, or could be result of quantification method limitation.

2. Materials and Methods

2.1. Distribution of Operating Facilities in the Gulf of Mexico

In 2022, nearly all US offshore oil and natural gas leasing and development activities happened in the Gulf of Mexico. On average, 1.8 million barrels per day (equivalent to 15% of the total US crude oil) and 0.8 Tcf natural gas (equivalent to 2.3% of the total US natural gas) were produced in the Gulf of Mexico [20–22]. The Bureau of Safety and Environmental Enforcement (BSEE) reported 1119 platforms and 147 rigs operating between Texas and Louisiana in the Gulf of Mexico in 2023 (Figure 1) [23]. Of these facilities, 806 were fixed leg platforms, 253 were caisson, 17 spar platforms, 15 semi-submersibles, 17 tension leg facilities, 6 well protectors, 2 compliant tower, 2 FPSOs (floating, production, storage and offloading) and 1 mobile production unit (Figure 1).

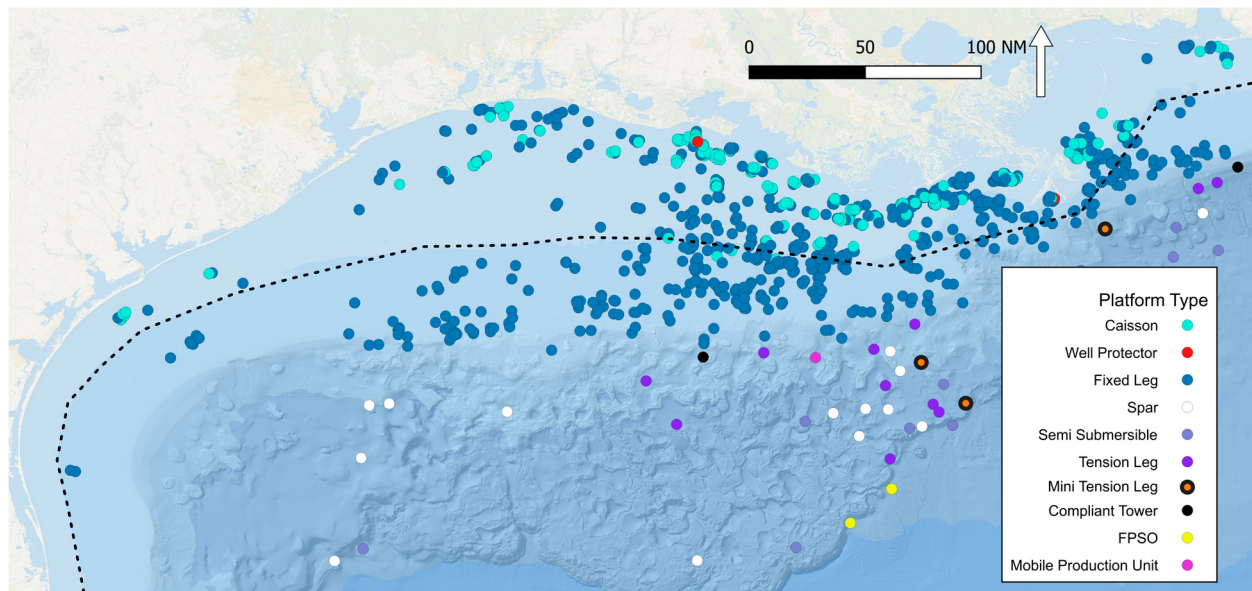


Figure 1. Distribution of the oil and gas production platforms in the Gulf of Mexico in 2022 using data published by BSEE [23]. The dashed line gives a nominal outline of the geographical split between prototypical facility type 1 and 2 fixed platforms. Type 1 prototypical facilities are generally closer to shore and in shallower water.

Fixed leg, well protector and caisson platforms are held up by legs fixed into the ocean floor and are deployed in water depths up to 1700 ft [24,25]. In each case, the subsurface infrastructure supports the deck where production, processing, and living facilities are housed. The 1065 fixed facilities are typically older (average install date of fixed leg

facilities was 1982), attached to fewer wellheads (average 2.6 well heads per facility), lower-producing (68 bbl oil day⁻¹ wellhead⁻¹; 238 Mscf natural gas day⁻¹ wellhead⁻¹), with a minimum of processing equipment (separators only), no storage tanks for oil or gas (all shipped directly to shore), and usually unmanned [23].

The other platform types are not directly fixed to the ocean floor and can therefore operate in deeper water [25]. Spar platforms work in water up to 10,000 ft and are fixed to a large floating vertical cylinder that is tethered to the seabed. Semi-submersible platforms are attached to submerged horizontal pontoons which are anchored to the seabed in depths up to 10,000 ft. Tension leg platforms also work up to 10,000 ft and comprise four air-filled pillars connected by a square-shaped pontoon structure that are fastened to the ocean floor using tendons that allows the platform to resist both vertical and rotational forces. Compliant tower platforms are connected to supports fixed to the seabed by a slender tower that absorbs/dissipates energy making them more stable and able to operate in the stronger currents found in deeper water up to 2750 ft deep. Floating Production Storage and Offloading (FPSO) facilities are designed to process and store produced oil in deep water (up to 8500 ft) and comprise a vessel that is fitted with all equipment needed to process and store oil and is moored to the seabed while receiving oil and gas from a subsea well. These 54 facilities are typically newer (average install date of 2007), more producing wellheads (average 4.0 well heads per facility), higher-production (1551 bbl oil day⁻¹ wellhead⁻¹; 1127 Mscf natural gas day⁻¹ wellhead⁻¹), more processing equipment (treater, headers, chemical injectors and dehydrators), contain storage tanks for oil (only gas is shipped directly to shore), and usually manned [23].

2.2. Calculating Emissions from a Facility Operating Normally

To generate an emission estimate for normal operations, we propose two prototypical facility types that are defined using production data and facility equipment data [23]. Prototypical facility type 1 are those fixed platforms operating closer to shore (<50 nm from shore) in shallower water (<200 m) that comprise typically older, lower-producing platforms with less processing equipment, no compressor, the oil is piped to shore and those usually unmanned 24 h per day (Figure 1, Tables 1 and 2). The second prototypical facility type define those platforms that operate in deeper water (>200 m), farther from shore (>50 nm from shore), are newer, have higher production rates from more well heads, have more processing equipment, oil storage tanks, compressors and power generation (Figure 1, Tables 1 and 2), and are usually manned 24 h per day. Henceforth, fixed leg, well protector and caisson platforms are defined as type 1 prototypical facilities and all other types of production platforms as type 2. Of note here, annual water, gas and oil production values are taken from published well head specific data, while the average number of producing well heads per facility is taken from facility data [23]. Specific wellhead numbers are not directly linked to specific platforms in the data and the average gas production is a calculated value.

Table 1. Average production rates from available well data.

Prototypical Facility Type	Average Number of Producing Well Heads Per Facility	Average Water Production (Mbbl y ⁻¹ well ⁻¹)	Average Gas Production (MMscf y ⁻¹ well ⁻¹)	Average Gas Production (kg h ⁻¹ facility ⁻¹)	Average Oil Production (Mbbl y ⁻¹ well ⁻¹)
1	2.6	114	87	480	25
2	4.0	357	411	3495	566

Table 2. Typical features of each type of production platform active in the Gulf of Mexico.

Platform Type	Count	Average Install Date	Average Deck Count	Manned 24 Hours Per Day (%)	With a Compressor (%)	With a Generator (%)	With Production Equipment (%)	With a Storage Tank (%)
Caisson	253	1992	1.7	1	2	4	72	2
Well Protector	6	1983	1.0	0	0	0	50	0
Fixed Leg	806	1982	2.3	23	38	47	84	28
Spar Platform	17	2005	3.4	94	100	100	100	65
Semi-Submersible	15	2014	1.7	93	93	93	93	73
Tension leg	14	2003	2.5	100	100	100	100	93
Mini Tension Leg	3	2003	3.3	100	100	100	100	67
Compliant tower	2	1999	3.5	100	100	100	100	100
FPSO	2	2013	0.0	100	100	100	100	100
Mobile Prod. Unit	1	2009	3.0	100	100	100	100	100

To generate likely average hourly methane emissions from each prototypical facility type, EPA emission factors [26–28] coupled with equipment activity data [23] were used. Following typical bottom-up modeling approaches [3,29,30], the emission (Q , $\text{kg CH}_4 \text{ h}^{-1}$) is calculated by multiplying an emission factor (E , $\text{kg CH}_4 \text{ A}^{-1} \text{ h}^{-1}$) by the activity, e.g., number of pieces of equipment or oil production rate (A) (Equation (1)). All emission factors and activity from all sources can be found in Tables S1 and S2.

$$Q = E \times A \quad (1)$$

The intention of this is not to generate actual emission estimates from but to calculate what would be the expected emission estimate (in $\text{kg CH}_4 \text{ h}^{-1}$) if emissions from a facility of that type were to be measured using a survey methodology, i.e., satellite, aircraft mass balance or a downwind dispersion approach [19]. As most of the emission sources on oil and gas production facilities work intermittently, e.g., separators and pneumatic controllers, we assume the emission factor is likely a time averaged value and lower than what would be observed during a survey; however, intermittency of emissions likely results in a subset of emissions being observed during the short observational period.

Recent studies have suggested that EPA emission factors could significantly underestimate emissions, by a factor of between 5 and 20 times, and mostly due to the under sampling of the right skewed emission distribution common of oil and gas emission profiles [31–33]. To investigate how much changes to emission factors could have on the hourly emission rate, we also include alternate emission factors taken from recent studies that either account for the long-tail distribution [34] or have previously been used to calculate emissions offshore [5].

2.3. Estimating Fugitive Emissions

Unlike process emissions described in Section 2.1, fugitive emissions are unexpected emissions that occur when equipment and gas pathways are compromised due to age or damage. Fugitive emissions are either continuous for sustained pressure vessels, e.g., on an export gas pipeline, or intermittent if the leaking piece of equipment undergoes pressure cycling, e.g., a pressure relief valve or flare on an overpressure relief system. To generate estimates of number of fugitives and expected size of emissions for each prototypical facility type, data were extracted from the 54 leak detection and repair (LDAR) surveys presented in the 2017 Gulf-wide Emission Inventory Study [3] and disaggregated by prototypical facility type. Average number of fugitives per facility and average emission rate per fugitive were calculated.

2.4. Maintenance Emissions

Maintenance emissions like vessel blowdowns can be very large (order of tons per hour) but are generally short duration events (usually sub-minute) depending on the size of vessel being blown down and the pressure of the gas. This means that these are likely only observed during unrepeated, snapshot observations, like satellite measurements. Most other methods will be either time averaged over a longer period, e.g., downwind dispersion, or will repeat observations, e.g., aircraft-based and mass-balance measurements. In this study we will not include maintenance emissions as we assume that either the observer has made repeat measurements of unusually large emissions suspected to be maintenance events or has contacted the operator to identify if a maintenance activity event has taken place during the observation window. In the event of observing a large emission event, we also assume the observer would attempt to reasonably match the reported emission duration to the observation duration. For example, for a single satellite observation lasting 10 s, we assume emissions have not been reported or extrapolated for longer time durations (hours, days, years) unless repeat measurements have been conducted or a reasonable attempt has been made to estimate the duration (i.e., how long did the maintenance event last).

2.5. Large Upset Emissions

In addition to maintenance emissions, we will also not include very large upset conditions in our estimate of the emission because we assume that any very large losses will be known to operators and could be determined from facility or pipeline metering. Large upset emissions would include events similar to those observed by Irakulis-Loitxate et al. (2022) [11], where sun-glint methods were used on satellite data to estimate methane emissions from the same facility in the Gulf of Mexico at $99 \text{ t CH}_4 \text{ h}^{-1}$ over a two-week period while flaring at the facility was on hiatus. While these observations are of interest to identify methods' detection limits in a real-world setting, the emission rate would be known to the operator via pipeline operator, much larger than the current expected emissions from offshore facilities ($83 \text{ kg CH}_4 \text{ h}^{-1}$ [5]), and likely the total production of multiple facilities in a higher production area ($\sim 30 \times$ total NG production of an average prototypical type 2 facility; Table 1; [11]). To comply with increased scrutiny, e.g., EU methane intensity or EPA superemitter tax requirements, operators need to be confident that methods can detect and quantify emissions at realistic emission rates. Here, we suggest that reported emissions larger than the average prototypical facility type 2 total production rate, i.e., $13 \text{ t CH}_4 \text{ h}^{-1}$, should be considered unrealistic.

2.6. Comparison with Observed Emissions

Recent measurement studies provide emission data from 294 platforms in the Gulf of Mexico. 151 platforms were measured using a shortwave infrared imaging spectrometer mounted on an aircraft to conduct sun-glint observations [6], 52 platforms were measured using an aircraft mass-balance method [8] and 103 measured using a downwind dispersion approach [18]. These data were first filtered to generate emissions from facilities most analogous to the bottom-up model estimate, i.e., no upset conditions or maintenance, and then emission directly compared with equipment known to be on each facility.

Using the emission data from 294 platforms in the Gulf of Mexico, a recent study [19] critically evaluated the measurements and generated four subsets: 1. Measurements that likely violated method assumptions; 2. Emissions that are defined as super emitters following the EPA definition of a facility emitting more than $100 \text{ kg CH}_4 \text{ h}^{-1}$; 3. Those that have emission less than a bottom-up derived minimum; 4. Emission from the remaining facilities. While it is easy to defend the removal of subsets 1 and 3, removing subset

2 includes the largest emissions, with an average emission of $1 \text{ t CH}_4 \text{ h}^{-1}$, and more difficult to rationally discount in analysis. Riddick et al. (2025) [19] suggest these large emission may result from making measurement in a decoupled marine boundary layer, where solar heating of clouds can result in stratification and a non-log linear relationship between altitude and wind speed which could result in overestimation by all three methods. For a comparison with our bottom-up model estimate, we only use emissions with an associated high confidence, i.e., subset 4 data. We assume that these are representative of working production facilities (both prototypical type 1 and 2) that are operating in non-upset condition, i.e., no maintenance or very large emission events. The subset 4 dataset includes emissions from 43 facilities with 8 measured using the aircraft spectrometer, 8 from the aircraft mass balance and 27 from downwind dispersion methods.

Data collated from the BSEE Data Center [23] were then used to determine the prototypical facility type based on the facility's distance to shore, water depth, presence of compressors and the presence of a produced liquid storage tank. Of the 43 facilities in subset 4, 10 of the facilities measured could not be geographically matched to a facility in the BSEE database. Of the remaining facilities, 1 was measured using the aircraft spectrometer, 7 from the aircraft mass balance and 25 from downwind dispersion methods. Production data during the time of the measurement were also extracted from the BSEE database and an estimate of the oil/gas production calculated and used to generate an estimate of the percentage of produced gas lost using the measured emission data. This percentage loss is used to evaluate the bottom-up emission estimate calculated for both prototypical facilities

3. Results

3.1. Emissions from a Facility Operating Normally

For prototypical facility type 1 and prototypical facility type 2 production platforms, a bottom-up model can be generated to estimate the size of expected emissions from process and fugitive emissions using EPA emission factors. As activity data are not available to explicitly estimate emissions from specific facilities, i.e., data matching individual well head production to facilities and equipment types on each facility, the estimates presented here are only to be used as a guide of what emission could be expected. Emissions are calculated from the average amount of produced gas/oil/water (Table 1), and the equipment used to process/store on the facility (Table 2).

3.1.1. Prototypical Facility Type 1

Most prototypical type 1 facilities are unmanned fixed platform producing oil and associated gas in near-shore (<50 nm), shallow (<6000 ft of water) areas (Table 2). It is estimated that average production from each well is 87 MMscf of gas, 25 Mbbls oil and 114 Mbbls water per year from an average of 2.6 well heads per platform (Table 1). Prototypical facility type 1 platforms include all Caisson/Well Protector platforms and Fixed leg facilities that are both less than 50 nm from shore and are in water less than 200 m deep (Figure 1). These facilities have emission sources that are either vented to atmosphere or vented to the flare. Sources vented to the atmosphere include pneumatic controllers, process equipment (chemical injectors and dehydrators), a produced water storage tank, and high pressure 2-phase and low pressure 3-phase separators. Upset conditions, i.e., over pressure in production lines are vented to a flare that is 98% efficient. Total operational emissions from a prototypical facility type 1 are estimated at $5.1 \text{ kg CH}_4 \text{ h}^{-1}$ with the largest emissions from pneumatic controllers ($2.0 \text{ kg CH}_4 \text{ h}^{-1}$) and produced water treatment ($2.2 \text{ kg CH}_4 \text{ h}^{-1}$) (Figure 2 and Supplementary Information Table S1).

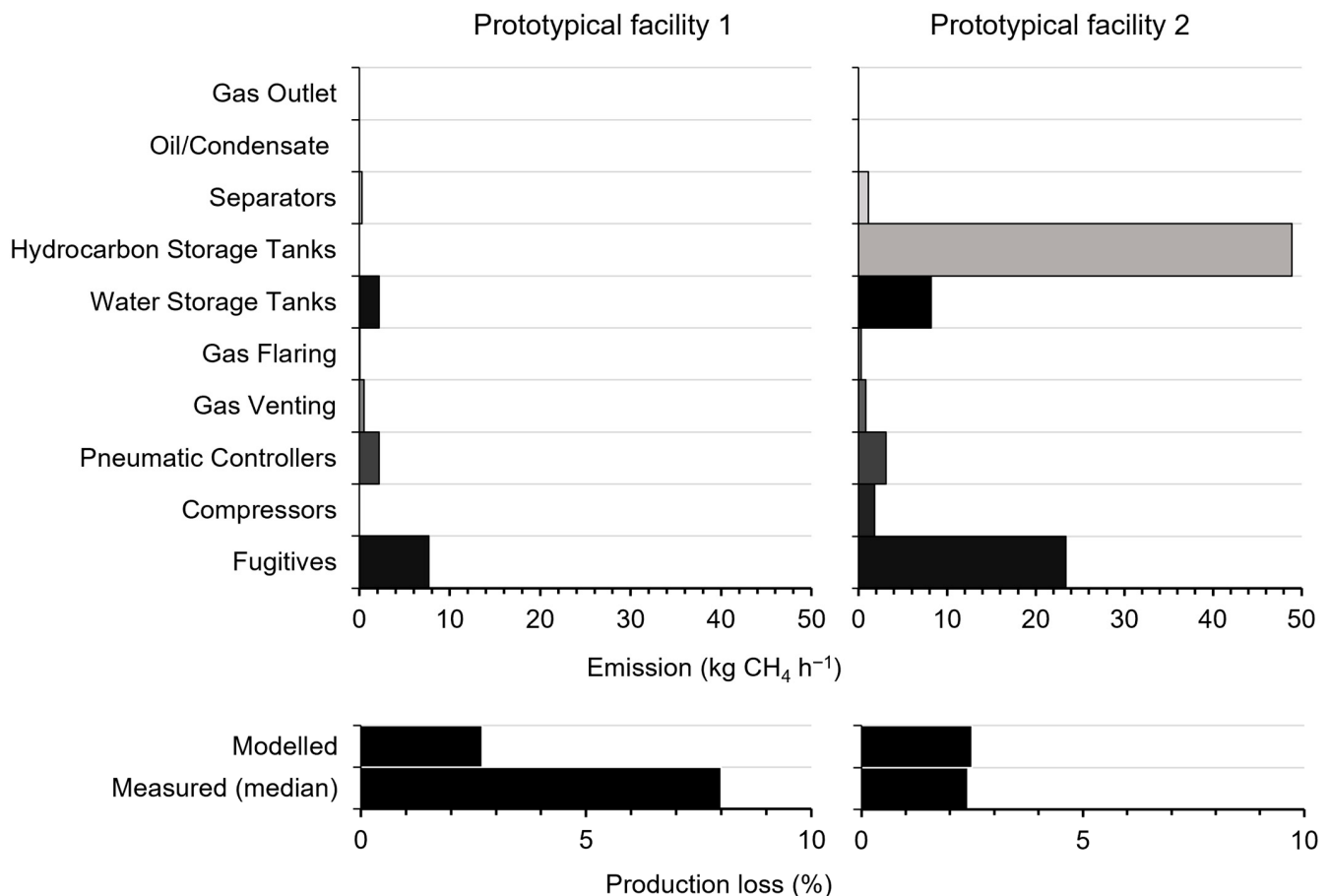


Figure 2. Modelled (absolute and percentage of production loss) and measured emissions (percentage of production loss) from prototypical Type 1 and 2 platforms during normal operations in the Gulf of Mexico.

3.1.2. Prototypical Facility Type 2

Even though there are key physical differences between Spar, Semi-Submersible, Tension leg, Compliant tower and FPSO platforms, there are many similarities that likely result in a common emission profile. All facilities have power generation, product storage tanks and compressors (Table 2). It is estimated that each well on this type of facility produces 411 MMscf gas, 556 Mbbls oil and 357 Mbbls water per year from an average of 4 well heads per platform (Table 1).

We will assume a prototypical facility type 2 facility consists of the following emission sources that are vented to the atmosphere: pneumatic controllers; process equipment (treater, headers, chemical injectors and dehydrators); condensate/oil storage tanks; a produced water storage tank; 9 low pressure 3-phase separators; one high pressure 2-phase separator; a glycol dehydrator; and gas turbines driving dry seal centrifugal gas export compressors. The expected average total emissions from processing equipment on deep water, higher production platform facility is estimated at 64.2 kg CH₄ h⁻¹ (Figure 2 and Supplementary Information Table S2). The largest emissions are from the liquid storage tanks (48.9 kg CH₄ h⁻¹), water storage tanks (8.2 kg CH₄ h⁻¹), and pneumatic controllers (3.1 kg CH₄ h⁻¹).

3.1.3. Note of Caution with Data

We add the caveat here that the numerical values presented above are for illustrative purposes only and give an emission estimate with a large uncertainty. The bottom-up estimates presented in Supplementary Information Tables S1 and S2 do not use the BOEM-

approved methodology as many of the variables required to generate a bottom-up method are unavailable to us (run time of equipment, gas to oil ratio values and volumes of vented gas). We also acknowledge many assumptions have been made (and described in Sections 3.1.1 and 3.1.2) and were made in lieu of data availability.

3.2. Fugitive Emissions

For the 43 Fixed Leg platforms, there was an average 12 fugitive emissions per platform with an average emission rate of 0.64 kg h^{-1} [3]. There were fewer fugitive emissions found on the FPSOs (12), but more on the Semi-Submersibles (18), Spar platforms (3) and Tension Leg platforms (15). Emission rates from the larger platforms are also larger than the average emissions from the simpler facilities. For the purposes of this study, we will use the Fixed Leg platform data for fugitive emissions from prototypical facility type 1 facilities (12 fugitive emissions per facility with an average emission of $0.64 \text{ kg CH}_4 \text{ h}^{-1} \text{ leak}^{-1}$) and the as the average of the larger facilities for prototypical facility type 2 facilities (13 fugitive emissions per facility with an average emission rate of $1.8 \text{ kg CH}_4 \text{ h}^{-1}$). It should be noted that component-based emission estimates for whole sites are inherently biased low as some fugitives can be missed from the survey; therefore, we suggest the average number of fugitives is realistically the lower bound.

3.3. Observed Emissions

3.3.1. Prototypical Type 1 Facilities

Of the remaining 33 facilities measured by either Yacovitch et al. (2020) [18], Ayasse et al. (2022) [6] and Gorchov Negron et al. (2023) [8], 13 were assigned as prototypical type 1 (Supplementary Information Table S3). All type 1 facilities were either Fixed leg (11) or Caisson (2) types. Average gas production is estimated at $1103 \text{ kg NG h}^{-1}$ for type 1 facilities, while average measured emissions are $17.6 \text{ kg CH}_4 \text{ h}^{-1}$. Assuming a methane content of natural gas of 93% [26] and using the facility specific production/emission data presented in Supplementary Information Table S3, this corresponds to a median production loss of 8% and mean production loss of 13%.

3.3.2. Prototypical Type 2 Facilities

Of the type 2 facilities, 15 were Fixed leg, 2 were Mini Tension Leg platforms, 2 were Tension Leg platforms and one was a Spar platform. From the BSEE production data, we estimate an average oil production at 2414 barrels per day and average gas production at $2338 \text{ kg NG h}^{-1}$ for type 2 facilities. Average measured emissions are $35.5 \text{ kg CH}_4 \text{ h}^{-1}$ which corresponds to a median production loss of 2.4% and mean production loss of 6%. Note that the average production losses did not include any of the facilities that were not on active leases or did not report any oil/gas produced during the measurement period. The average emission from non-producing sites was $27 \text{ kg CH}_4 \text{ h}^{-1}$, with $8 \text{ kg CH}_4 \text{ h}^{-1}$ from type 1 facilities and $31 \text{ kg CH}_4 \text{ h}^{-1}$ for type 2 facilities.

4. Discussion

4.1. Calculated Bottom-Up Emission Estimates

Operational emissions from a prototypical facility type 1 are estimated at $5.1 \text{ kg CH}_4 \text{ h}^{-1}$ with the largest emissions from water treatment ($2.2 \text{ kg CH}_4 \text{ h}^{-1}$), pneumatic controllers ($2.0 \text{ kg CH}_4 \text{ h}^{-1}$) and chemical injection pumps ($0.5 \text{ kg CH}_4 \text{ h}^{-1}$) (Figure 2 and Supplementary Information Table S1). Fugitive emissions are estimated at $7.7 \text{ kg CH}_4 \text{ h}^{-1}$ with 12 fugitive emissions per facility with an average emission of $0.64 \text{ kg CH}_4 \text{ h}^{-1} \text{ leak}^{-1}$. Total emissions from a prototypical facility type 1 are estimated at $12.8 \text{ kg CH}_4 \text{ h}^{-1}$, correspond to a loss of 2.7% of the average facility production of $480 \text{ kg CH}_4 \text{ h}^{-1}$.

The expected average total emissions from processing equipment on a deep water, higher production platform (prototypical facility type 2) is estimated at $64.2 \text{ kg CH}_4 \text{ h}^{-1}$ (Figure 2 and Supplementary Information Table S1). The largest emissions are from the liquid storage tanks ($48.9 \text{ kg CH}_4 \text{ h}^{-1}$), water storage tanks ($8.2 \text{ kg CH}_4 \text{ h}^{-1}$), and pneumatic controllers ($3.1 \text{ kg CH}_4 \text{ h}^{-1}$). Fugitive emissions are estimated at $23.4 \text{ kg CH}_4 \text{ h}^{-1}$ with 13 fugitive emissions per facility with an average emission rate of $1.8 \text{ kg CH}_4 \text{ h}^{-1}$. Total emissions from a prototypical facility type 2 are estimated at $87.6 \text{ kg CH}_4 \text{ h}^{-1}$, corresponding to a loss of 2.5% of the average facility production of $3495 \text{ kg CH}_4 \text{ h}^{-1}$.

The prototypical facility type 1 hourly emission calculated using the standard EPA emission factors ($12.8 \text{ kg CH}_4 \text{ h}^{-1}$) are very similar to the emission estimate calculated using updated emission factors (Supplementary Information Table S4; $15.5 \text{ kg CH}_4 \text{ h}^{-1}$). We suggest this is just simply a function of the facilities' simplicity where gas is taken onto the facility, split into gas, oil and water, and then exported to the shore. Prototypical facility type 2 are more complex and therefore have the potential to be more emissive. Updating the emission factors suggests the emission from the compressors and the produced liquid tanks could be underestimated by at least a factor of two (Supplementary Information Table S5). However, the increase in emission from 88 to $137 \text{ kg CH}_4 \text{ h}^{-1}$ is relatively small, within the uncertainty of the measurements methods used offshore (between -50% and $+100\%$ [18]) and using emission factors that do not account for a long-tail emission distribution [31,34,35] cannot be used to explain the very highest emission estimates reported by studies using aircraft methods [6,8].

4.2. Measured Emissions

Of the 13 type 1 facilities that were measured and had production/equipment data, average emissions were $17.6 \text{ kg CH}_4 \text{ h}^{-1}$ and median production loss estimated at 8% (Figure 2 and Supplementary Information Table S3). The difference between the measured and modelled median production loss is a factor of 3 (modelled: 2.7%). As mentioned above, there are few moving parts and no storage tanks on Type 1 facilities, so vented emissions are likely a small fraction of the total emission (Figure 2 and Supplementary Information Table S1). The largest unknown emission source on a Type 1 facility are fugitives (Figure 2 and Supplementary Information Table S1). Data on the relative size and number of fugitives is meagre with the emission estimate used in this study coming from leak detection and repair (LDAR) surveys of 43 platforms (average number of fugitives is 12 with average size $0.64 \text{ kg CH}_4 \text{ h}^{-1}$). LDAR studies are inherently biased low as they only include leaks found and do not account for any in hard to measure place or intermittent leaks. Type 1 facilities are typically older (average install date of Caisson facilities in 1992 and Fixed Leg 1982) and are largely unoccupied which means fugitives are less likely to be observed and repaired (Table 1). This provides a rationale for the discrepancy between the modelled and measured emission rates, and we therefore suggest that 6% of production is currently lost as fugitive emissions from Type 1 facilities.

Of the 20 type 2 facilities with data measured, average measured emissions were $35.5 \text{ kg CH}_4 \text{ h}^{-1}$ corresponding to a median production loss of 2.4% (calculated from gas production and emission data in Supplementary Information Table S3). The measured and modelled median production loss is almost equal (modelled: 2.5%) suggesting reconciliation between top-down and bottom-up for these types of facility.

Despite the differences for type 1 facilities that can be explain by fugitives, we can consider that bottom-up modelling can be used to generate representative emission estimates from operating offshore production facilities if production rates and equipment types are known. We suggest the main weakness in emission quantification is the estimate of the size and number of fugitive emissions on the facility, especially for the generally older type

1 facilities. This could be better calculated using LDAR surveys with either optical gas imaging or spectrometers mounted on drones. Regardless of method, more data would help to reconcile the modelled and measured emission estimate. We must note again here that, short of a catastrophic emission event that is likely to result in a noticeable reduction in gas production rate, emissions are unlikely to exceed the super-emitter threshold ($100 \text{ kg CH}_4 \text{ h}^{-1}$) without being caused by the operator (maintenance, oil unloading or vented for safety).

4.3. Recognizing Real Large Emission Events and Quantification Best Practices

While we recognize that bottom-up methods of quantifying methane emissions from oil and gas production infrastructure have many shortcomings, we have shown here that models that incorporate both equipment types and production rates can be used to generate emission estimates representative of measured emissions. We suggest that the main difficulty in reconciling modelled and measured emission estimates is the current understanding of the number and size of fugitive emissions on both the lower and higher production facilities. Currently LDAR survey are conducted through AVO detection, which means that the leaks could remain undetected on unmanned facilities or those that are larger and have more hard-to-reach areas. This could be addressed by conducting more LDAR surveys with a range of methods that can quantify total facility emissions.

Even though the sizes of fugitive emissions are not completely known, they could not be used to account for the very largest disparities between modelled and measured emission estimates. Some measured emissions presented in publications are larger than the average gas production rates of type 2 facilities ($>3480 \text{ kg CH}_4 \text{ h}^{-1}$), which either means an error in measurement or catastrophic failure of the production equipment. Here we suggest the bottom-up approach presented in this study that includes equipment types and production rates could be used to generate a representative emission rate and used as a metric to identify those measured emissions that should be targeted for further investigation. In the event of a large emission event, operators can be contacted to determine if maintenance is being carried out. If the measurement timing does not coincide with a known event, remeasurements could be made. In all cases, we suggest that this relatively quick bottom-up approach can be used as a validation check on measured values to give more confidence to whole facility quantification.

The rationale for this is to generate a more reasonable time averaged emission estimate. For example, if the emission from a production facility in the Gulf of Mexico is observed to be $1145 \text{ kg CH}_4 \text{ h}^{-1}$ during a 30 s measurement [6], it would be unreasonable to extrapolate this up to an hourly, daily or annual emission without an understanding of the driver of the emission and reasonable assumption made about the duration.

Our study highlights two important unknowns in quantifying methane emissions from offshore facilities. Firstly, the understanding of the number and range of sizes of fugitive emissions from offshore facilities. Annual measurements are made and reported as part of the US Department of the Interior, Bureau of Ocean Energy Management's Gulf of Mexico OCS Region report [3]; however, these data are not exhaustive and do not include fugitive emission counts from all facilities operating in the region. Fugitive emissions also present a safety risk particularly on unmanned facilities. Therefore, we suggest in the interests of both safety and improving the understanding of expected emissions LDAR surveys should be carried out on as many facilities as possible.

Secondly, there remains uncertainty over the uncertainty of measurement methods to quantify emissions. This question has been asked by other studies, e.g., Riddick et al. (2025) [19], where it has been suggested that current offshore emission quantification methods are either capable of missing the downwind plume or overestimating the emis-

sion by an unreasonable amount. Here we suggest future studies could investigate if measurement methods' assumptions of a logarithmic wind profile are reasonable and in which atmospheric conditions the assumptions are likely to be violated. In this way, future measurements can be assigned an understanding of how accurate the observer feels the emission are and increase the confidence in the observation.

4.4. Future Use of the Bottom-Up Emission Estimates

In addition to a reference tool for expected emission (as outlined in Section 4.3), we intend to use the emission estimates generated by this study to inform emission experiments as part of METEC2.0 development funded by the U.S. Department of Energy's Office of Fossil Energy and Carbon Management. The METEC2.0 project will enhance the capabilities of Colorado State University's Methane Emissions Technology Evaluation Center (METEC) to decarbonize natural gas resources. In particular, Task 6 of METEC2.0 extends METEC current capabilities to offshore testing and will design and develop an offshore methane emissions test facility and maintain it in operational condition for testing.

The development of an offshore testing program requires a realistic understanding of the size, location and behavior (point of diffuse source) of emission typical of offshore production facilities. The findings of this study indicate that representative individual emission rates from processing equipment from offshore production facilities are likely to range from tens of $\text{g CH}_4 \text{ h}^{-1}$ (e.g., emissions resulting from dehydrator) to tens of $\text{kg CH}_4 \text{ h}^{-1}$ (e.g., emissions from hydrocarbon stage tanks). Emissions from individual, point source fugitives are likely to be between 0.5 and 3 $\text{kg CH}_4 \text{ h}^{-1}$, with larger emissions on type 2 prototypical facilities (Table 3). However, the reconciliation of the top-down and bottom up suggests that the number of fugitives could be much larger than previously estimated by a factor of four, i.e., ~50 leaks per offshore facility.

Table 3. Average number, total emission and average fugitive emission measured during LDAR surveys.

Type	Number Platforms Surveyed	Average # Fugitives	Average Total Emission (kg h^{-1})	Average Emission per Leak (kg h^{-1})
Fixed Leg	43	12	7.7	0.64
FPSO	1	4	11.9	2.99
Semi-Submersible	3	18	28.3	1.57
Spar	3	16	20.8	1.30
Tension Leg	4	15	21.4	1.42

These results suggest that to create a realistically emitting type 1 offshore facility, a total of 39 $\text{kg CH}_4 \text{ h}^{-1}$ should be emitted from the facility, with ~5 $\text{kg CH}_4 \text{ h}^{-1}$ emitted as a diffuse source from the working deck where processing equipment is located and many more point sources (fifty-six 0.6 $\text{kg CH}_4 \text{ h}^{-1}$ emissions) around the facility. For a realistic type 2 prototypical facility, we estimate total emissions of 88 $\text{kg CH}_4 \text{ h}^{-1}$, with a larger diffuse source from the working deck (~64 $\text{kg CH}_4 \text{ h}^{-1}$) and fewer simulated fugitive point sources (thirteen 1.8 $\text{kg CH}_4 \text{ h}^{-1}$ emissions).

5. Conclusions

This study investigates using a bottom-up approach to generate realistic methane emission estimates from oil and gas production facilities in the Gulf of Mexico. We created bottom-up models that simulate two prototypical facility types and compared the calculated emissions to emissions reported by published studies. Prototypical facility type 1 are fixed platforms operating closer to shore in shallower water and comprise typically older, lower-producing platforms with less processing equipment, no compressors, where the oil is

pipled to shore and they are usually unmanned 24 h per day. Using the bottom-up model, total emissions from a prototypical facility type 1 were estimated at 12.8 kg CH₄ h⁻¹, with the largest emissions from fugitive emissions, water treatment, and pneumatic controllers. This corresponds to a loss of 2.7% of the average facility production of 480 kg CH₄ h⁻¹.

Prototypical facility type 2 platforms operate in deeper water, farther from shore, are newer, have higher production rates from more well heads, have more processing equipment, oil storage tanks, compressors and power generation, and are usually manned 24 h per day. Total emissions from prototypical type 2 facilities were estimated at 87.6 kg CH₄ h⁻¹ (loss of 2.5% of the average facility production), with the largest emissions from the liquid storage tanks, water storage tanks, and compressors. Fugitive emissions were estimated at 23.4 kg CH₄ h⁻¹, with 13 fugitive emissions per facility with an average emission rate of 1.8 kg CH₄ h⁻¹.

The average measured emission from type 1 facilities was 17.6 kg CH₄ h⁻¹ with a median production loss of 8%. As there are few moving parts and no storage tanks on type 1 facilities, the largest unknown emission source were fugitives and we therefore suggest that 6% of production is probably lost as fugitive emissions from type 1 facilities. The measured average emission from type 2 facilities was 35.5 kg CH₄ h⁻¹ with a median production loss estimated at 2.4%.

Using emission factors that consider the long-tail emission distribution partly reconciles the difference between modelled and measured emission estimates, but we suggest the current the fugitive emission estimate may be an underestimate and more data on the number and size of fugitive emissions could help to reconcile the modelled and measured emission estimate. We suggest a bottom-up approach that uses production data coupled with facility equipment could be used to identify facilities that have unusually large measured emissions, caused by either methodological failure in measurement or significant fugitive emissions, which should be targeted for further evaluation resulting in remeasurement or identification of source type (maintenance event or fugitive) so that a more accurate estimates can be made on the absolute emission.

Supplementary Materials: The following supporting information can be downloaded at: <https://www.mdpi.com/article/10.3390/eng6080199/s1>, Table S1: Estimated emissions from Type 1 platforms during normal operations; Table S2: Estimated emissions from Type 2 facilities during normal operations; Table S3: Data for platforms measured in the Gulf of Mexico; Table S4: Estimated emissions from Type 1 facilities during normal operations using emission factors that account for the long tail distribution. Emission factors taken from recent literature; Table S5: Estimated emissions from Type 2 facilities during normal operations using emission factors that account for the long tail distribution. Emission factors taken from recent literature.

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