

Colorado (CDPHE/AQD) Rule Making Verifying Methane Emissions Reporting

June 2023

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Abstract

Reducing greenhouse gases, especially methane emissions, from oil and gas production activities is one of the major themes of regulatory actions both at state, provincial and federal levels in North America as part of society's path for addressing climate change. Reducing methane emissions is also a priority of the oil and gas industry, not only to reduce waste and increase production, but to comply with growing regulations and investor demands. There is a growing awareness and commitment by all stakeholders (producers, regulators, and community organizations) for a stronger culture for environmental stewardship. But this shared awareness has not led to increased trust between parties.

One of the biggest barriers for methane reduction is not financial or technology, but rather a lack of rigorous and transparent data. As one example of the growing interest in emerging measurement technologies rather than estimation of engineering factors, this research paper follows the work of the Colorado Department of Public Health and Environment's Air Pollution Control Division and looks at the implications and new expectations from a 'measure what matters' approach regarding methane monitoring and air quality improvements in the state.

In 2021, Colorado's Air Quality Control Commission adopted a rule that limits how much greenhouse gas can be emitted per barrel of oil and gas produced. However, the 2021 GHG intensity rule left open the critical question of how oil and gas operators can demonstrate that their emissions comply with the new standard.

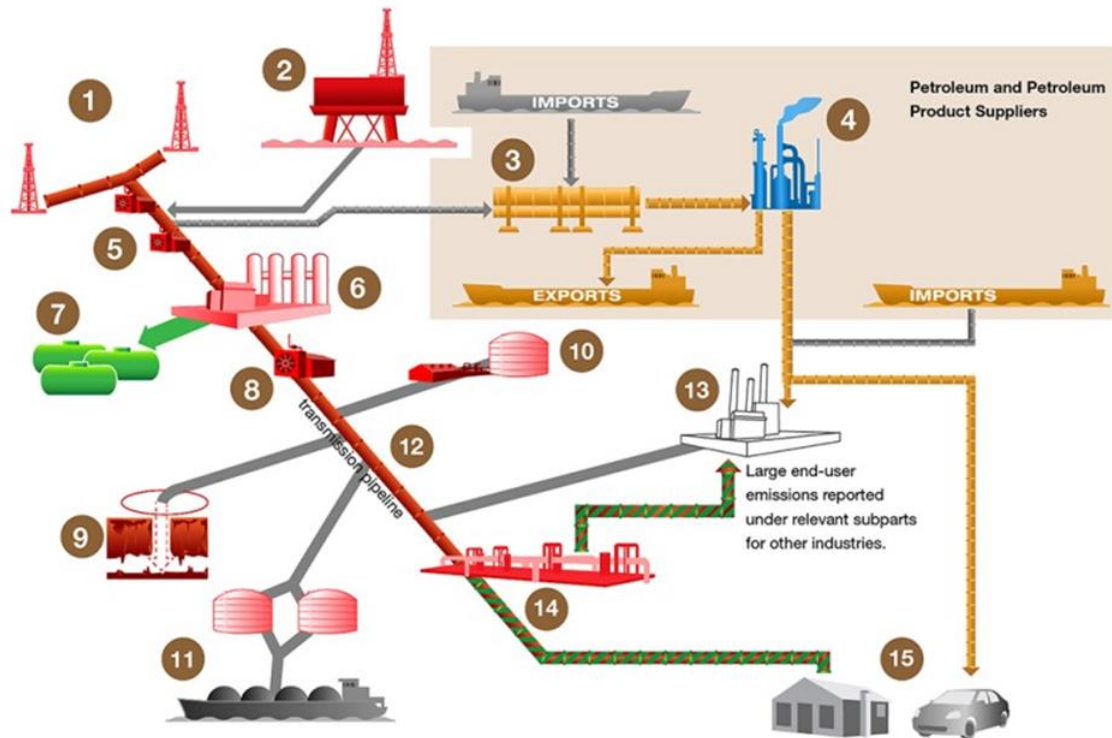
The Colorado Air Pollution Control Division is developing a new rule making for revision to Regulation No. 7 and 22, Part B, Section IV and the accompanying draft guidance for an updated intensity verification rule to ensure a reduction in greenhouse gas emissions from oil and gas upstream operations to meet the state’s net-zero carbon 2050 roadmap target. This program is part of the state’s approach to address climate change.

Intensity is a measure of greenhouse gas emissions over the amount of oil and gas produced in the form of energy. Oil and gas upstream operators must comply with new intensity requirements, which will decrease (hopefully leading to more emission reductions) over the course of five years (2025 - 2030). This rulemaking defines how operators calculate their greenhouse gas intensity, monitor operations to ensure compliance, and account for all emissions from their operations.

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Production & Processing

- 1. Onshore Petroleum & Natural Gas Production
- 2. Offshore Petroleum & Natural Gas Production
- 3. Total Crude Oil to Refineries
- 4. Petroleum Refining
- 5. Gathering and Boosting
*Data collection began in RY 2016
- 6. Gas Processing Plant
*May contain NGL Fractionation equipment
- 7. Natural Gas Liquids (NGL) Supply

Natural Gas Transmission & Storage

- 8. Transmission Compressor Stations
- 9. Underground Storage
- 10. Liquefied Natural Gas (LNG) Storage
- 11. LNG Import-Export Equipment
*Data collection began in RY 2016

Distribution

- 12. Natural Gas Transmission Pipeline
- 13. Large End Users
- 14. Natural Gas Distribution
- 15. Natural Gas & Petroleum Supply to Small End Users

	Subpart W: Emissions from petroleum & natural gas systems
	Subpart Y: Emissions from petroleum refineries
	Subpart MM: CO ₂ associated with supplies of petroleum products
	Subpart NN: CO ₂ associated with supplies of natural gas & natural gas liquids
	Not reported under GHGRP

Petroleum and gas entities subject to EPA’s GHG Emission Reporting Program. Source: Congressional Research Service/EPA. This image is how the US EPA sees the value chain. The scope of the current Colorado rule making is only focused on step one.

Introduction

- A process that is not measured cannot be understood
 - A process that is not understood cannot be controlled
 - A process that is not controlled cannot be standardized
 - A process that is not standardized cannot be optimized
 - A process that is not standardized is difficult to automate
- Optimization precedes automation

In order to curb fugitive emissions, governments are mandating Leak Detection and Repair (LDAR) programs such as US EPA Method 21, Canada Directive 060, and European Method EN 15446. Independent

measurement and monitoring efforts on industrial activities are helping regulators to form more accurate guidelines for public decarbonization objectives. Adoption of new technologies and techniques are also helping energy companies improve the environmental footprint of their operations. After all the methane emissions are a wasted product and it benefits the operator by reducing emissions and increasing production. Most forecasters believe that oil and gas will remain a significant source of energy in the power, transportation, and chemicals sectors for several more decades at least. The oil and natural gas industry is responsible for 339,500 jobs in Colorado alone. In one year, oil and natural gas contributes \$46.1 billion to the Colorado economy. Natural gas is a valuable asset that no one wants to waste. (Bowser & Bazilian, 2022)

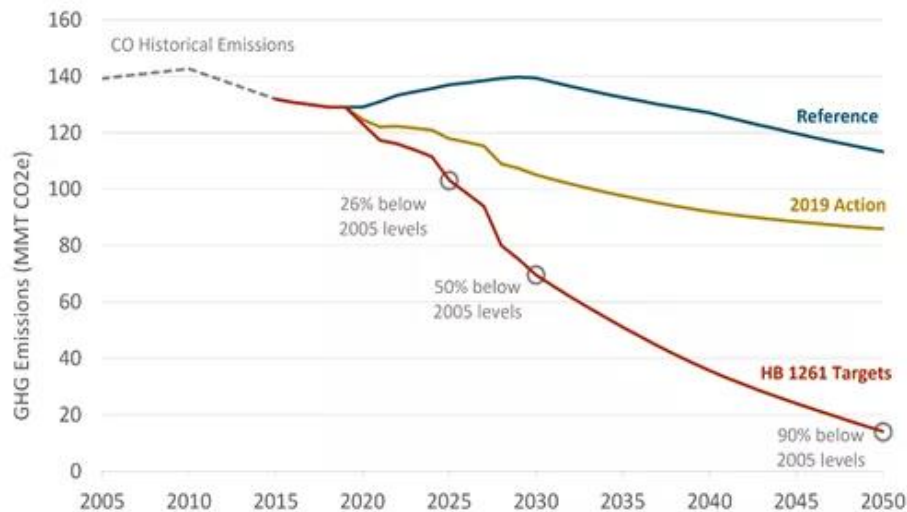
There is even a growing market for ‘responsibly sourced’ natural gas (RSG) which provides a positive market signal for improving operations. Some stakeholders do not like the term RSG but would prefer a more neutral term like certified natural gas. But the task of developing measurement and monitoring infrastructure for an industry in Colorado that includes 50,499 oil and gas wells (as of April 2021) and about 430 operators on record (although there were only 147 operators that responded to the APCD’s LDAR report in 2021) will not be a simple task.

We have found that the subject of verifying methane emissions from the oil and gas sector is a complex topic. While our paper covers a lot of elements to this story, the primary purpose of this research is to follow the current rule making process by the Colorado Department of Public Health and Environment (CDPHE) Air Pollution Control Division (APCD) for verification of methane emissions reporting and to discuss the major implications of the new rules. Our intent was not to influence the rule making process but to seek to understand the consequences for each of the many and diverse stakeholders. So, it seems reasonable to start with the purpose that the Division states in their initial draft.

“During the 2019 legislative session, Colorado’s General Assembly adopted House Bill 19-1261 (HB 19-1261), setting statewide greenhouse gas (GHG) reduction goals. The General Assembly declared in HB 19-1261 that “climate change adversely affects Colorado’s economy, air quality and public health, ecosystems, natural resources and quality of life,” acknowledged that “Colorado is already experiencing harmful climate impacts” and that “many of these impacts disproportionately affect” certain disadvantaged communities. The goals set in HB 19-1261 seek a 26% reduction of statewide GHG emissions by 2025, 50% reduction by 2030, and 90% reduction by 2050 as compared to 2005 levels. The GHG Pollution Reduction Roadmap (“GHG Roadmap”) developed by the Colorado Energy Office and CDPHE identifies the largest contributors to state GHG emissions and quantifies the baselines from which these reduction percentages are to be estimated.”

“In December 2021, the Commission adopted revision to this regulation that required owners or operators to submit greenhouse gas intensity plans. The primary purpose of these plans is for owners or operators to demonstrate to the Division how they intend to meet the 2025, 2027 and 2030 greenhouse gas intensity targets in Section IV.B.2 through IV.B.4. In Section IV.F., the Commission directed the Division to develop a mechanism to track progress towards meeting the state’s GHG reduction goals and to evaluate compliance with the greenhouse gas intensity targets and new facility intensity targets in Section IV.B and IV.C. The Commission determined that it was advisable to give the Division time: 1) to evaluate the annual emission reports submitted in 2021 and 2022, 2) to evaluate different calculation and emissions quantification methodologies for different emitting activities and equipment, and 3) to consider the impact and results of the aerial and ground-based survey work being conducted by the Division (and contractors) in 2021 (because this data was not fully available until the spring of 2022) as well as other relevant surveys. The Commission directed the Division to, by 2023, propose a verification plan after considering the current status of oil and gas GHG emissions, based on Regulation Number 7 reporting and top-down monitoring results, production increases or decreases based on data reported to the COGCC, the aerial and ground-based survey work, and other important considerations, such as the availability, reliability, and cost-effectiveness of direct measurement techniques as appropriate.”

2020 CO GHG Emissions (MMT CO₂e, AR5 100-yr GWP)



Colorado's Roadmap GHG Emissions Scenarios

<https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap>

What is Greenhouse gas intensity?

While there may be different definitions in use for this ratio, we again turn to the draft APCD policy to use the approach that will soon be adopted into law.

“Greenhouse gas intensity calculates GHG emissions, reported in terms of carbon dioxide equivalents, emitted by an upstream oil and gas operator divided by that operator’s all oil and natural gas production for that calendar year. Emissions of all GHGs will be aggregated in metric tons of carbon dioxide equivalents per year (mtCO₂e/year) and calculated per 100-year time horizon global warming potential (GWP) values. The following calculation will determine GHG intensity:

$$\text{GHG Intensity (mtCO}_2\text{e/kBOE)} = \frac{\text{Total Annual GHG Emissions (mtCO}_2\text{e/year)}}{\text{Total Annual Production (KBOE/year)}}$$

- $\text{Total Annual GHG Emissions (mtCO}_2\text{e/year)} = \text{Methane Emissions (mtCO}_2\text{e/year)} + \text{Carbon Dioxide (mtCO}_2\text{e/year)} + \text{Nitrous Oxide Emissions (mtCO}_2\text{e/year)}$
- $\text{Total Annual Production (kBOE/year)} = \text{Oil Production (kBOE/year)} + \text{Gas Production (kBOE/year)}$

The division will reconcile calculations of GHG emissions based on current inventory methods with actual measurements of methane taken at the regional or facility level through the derivation of a state-wide methane verification factor. The division will define how it will generate the state-wide verification factor and outline how it will iteratively improve the methane verification factor.”

What is intensity?

$$\frac{\text{Annual Total Emissions}}{\text{Annual Total Production}} = \text{Intensity}$$

- Annual Total Emissions =** Production and preproduction GHG emissions per company (metric tons carbon dioxide equivalent, mtCO₂e)
- Annual Total Production =** Oil and Natural Gas production per company (thousand barrels of oil equivalent, kBOE)
- Intensity =** Company intensity for single year (mtCO₂e/kBOE)

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The problem with using methane intensity as a metric

As described above, the Air Pollution Control Division has proposed to use the metric of methane intensity as a key metric in tracking the performance of oil and gas operators in their goal of reducing greenhouse gas emissions. There was considerable debate when the intensity rule was adopted in 2020. The benefits of this metric are that it is easy to calculate (amount of emissions/ total production) and that methane intensity is used by several oil and gas industry consortiums (OGCI in particular) and many operators to track their performance and progress towards reducing emissions. The 2020 rule also required more frequent inspections and improved pipeline cleaning and maintenance practices and set emissions targets for operators based on the amount of oil and gas they produce. That gets to the controversy around methane intensity.

There are critics of using this measure in the environmental community. Let us use this example to explain what the critics are concerned about. To simplify the math, let us assume that an operator’s current methane intensity is 1.0%. That would equate to 100 mt of CO₂e emitted per year per 10,000 kBOE of crude oil and natural gas produced per year. Now let us assume the operator makes specific investments (instrument air pneumatic controllers, uses grid electricity instead of diesel engines, applies a continuous monitoring solution to more quickly identify and repair fugitive leaks, etc.).

But the operator also applies for and receives new drilling permits from the state and can increase their production by 10% by drilling new more productive wells. If production was steady (and it usually is not due

to normal reservoir pressure decline leading to lower production per well, moving to a methane intensity of 0.2% would mean 20 mt of CO₂e emissions per 10,000 kBOE of crude oil and natural gas produced or a significant reduction of 80 mt CO₂e.

But if the total production increased by 10% to 11,000 kBOE if natural gas, at a methane intensity of 0.2%, the total emissions would be 22 mt CO₂e, resulting in 2mt more than targeted. Using an intensity ratio allows the operator to increase production and reduce methane intensity at the same time. If the operator's emissions remain constant at 100 mtCO₂e and increased production through only a slight modification of their LDAR program, the methane intensity would decline to 0.9% appearing to the public of a decrease but with the same level of methane emissions. Therefore, many critics do not like the ratio of methane intensity based on total energy produced.

Another one of the challenges with methane intensity is for facilities that produce mostly crude oil and some associated natural gas. If the intensity is calculated by total energy (BOEG) then the methane emissions are associated with the total production and will therefore be a smaller factor. If the methane intensity is just over the gas volume (MCF) then you have a more specific measure of the gas leakage rate. The Colorado definition is over total energy. For oil and associated gas wells (like the DJ basin) they could be singled out as a large emitter if you compare the methane to the small volume of natural gas produced or one of the best if you compare the emissions to the total volume of hydrocarbons produced. For purely natural gas production from the western slope, the situation is different. It is all is how you define methane intensity. There is no agreement on which metric is right.

Setting methane intensity targets – (there are a lot of different examples)

- OGCI has a 2025 target of well below 0.2% of marketed gas from operated assets.
- Chevron has set an upstream methane intensity target of 2.0 kg CO₂e by 2028 (Chevron 2022). This is equivalent to about a 0.18% methane intensity metric.
- Civitas Resources is Colorado's first carbon neutral energy producer. Civitas has a 2.5% fixed emissions intensity target against the 2019 EPA reporting baseline on a 10-year average to account for effects of acquisitions (Civitas, 2022)
- Occidental Petroleum - As a member of the API-sponsored Environmental Partnership and OGCI, we set a short-term target in 2020 to reduce methane emissions below 0.25% of their total produced and marketed natural gas volume by 2025. (Occidental, 2023)
- Global Methane Pledge reduction of at least 30% from 2020 levels by 2030.
- US Methane Emissions Reduction Action Plan of November 2022, reduction of methane emissions by 75% by 2030 (IEA, 2021)
- COGA claims that the “Colorado molecule” or the oil and natural gas molecules produced in Colorado are among the cleanest in the world. Under Colorado's rigorous regulatory framework and environmental rules that are widely seen as the gold standard.
<https://www.coga.org/factsheets/colorado-molecule>

Qualifying emerging technology, chasing a moving target

The good news is that technology to measure GHG emissions is rapidly improving and new tools and techniques are coming to the market at a fast pace. The not so good news is the challenge for regulators to certify which technologies should be used by operators to meet regulatory targets. A prescriptive approach brings clarity but might bypass an emerging solution. A more open, non-prescriptive approach allows for innovation but bring more debate as to the validity of the measurements from novel techniques.

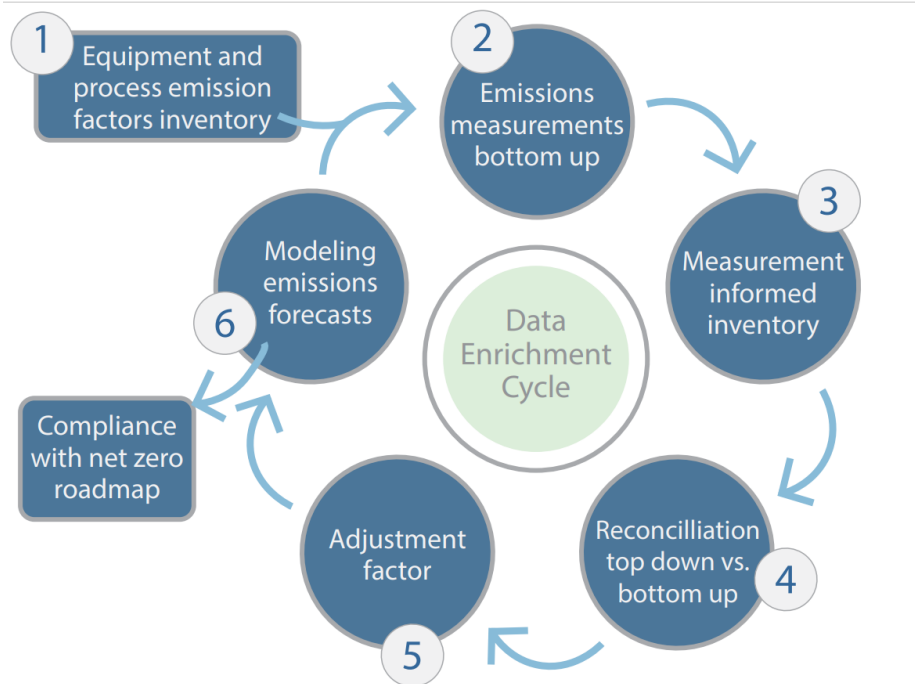
Current regulations tend toward to a more detailed prescriptive philosophy. By today's state law: an Approved Instrument Monitoring Method (AIMM) must be used to inspect components, storage tanks and natural gas-driven pneumatic controllers at well production facilities, natural gas compressor stations, and natural gas processing plants (storage tanks only) under the Leak Detection and Repair (LDAR), Storage Tank Emission Management (STEM) and Natural Gas-Actuated Pneumatic Controller requirements of Air Quality Control Commission (AQCC) Regulation 7.

AQCC Regulation 7 defines AIMM as an infrared (IR) camera, EPA Method 21, or other instrument-based monitoring method or program approved in accordance with the requirements of Regulation 7, Part D, Section I.L.8 ("Alternative AIMM"). <https://cdphe.colorado.gov/oil-and-gas-and-your-health/approved-instrument-monitoring-method-aimm-for-oil-gas>

In 2014 the Colorado Air Quality Control Commission (AQCC) adopted amendments to AQCC Regulation No. 7 to complement the partial adoption of the federal New Source Performance Standard, Subpart OOOO, Emissions Standards for New, Reconstructed and Modified Sources in the Oil and Natural Gas Sector (NSPS OOOO). These amendments included use of Approved Instrument Monitoring Methods (AIMM), as defined in AQCC Regulation No. 7, to identify and reduce hydrocarbon emissions from certain oil and gas operations. The amendments also provide the ability for the Air Pollution Control Division to approve additional AIMM beyond those specified in the regulation. As a result, the Division developed criteria and a process for review and approval of such AIMM, which are referred to as "Alternative AIMM". <https://oitco.hylandcloud.com/CDPHERMPop/docpop/docpop.aspx> (Sorry for all the government-speak)

But the certification of new technologies can be a lengthy and detailed process. *"The EPA has received comments from industry, state agencies, and non-governmental organizations, acknowledging that review and approval of individual monitoring plans increase the burden on industry and regulatory bodies. To overcome this problem, EPA proposed that once an alternative method has been approved, any owner or operator will be able to deploy it. To streamline the application process, EPA proposed that applications for an alternative method must contain the following information at a minimum: (1) The desired applicability of the technology, (2) A description of the measurement systems, (3) Supporting information verifying that the technology meets the desired detection threshold(s) as applied in the field (4) A detailed description of the alternative testing procedure(s) (5) Standard operating procedures. Finally, the EPA proposed a defined timeframe to issue either an approval or disapproval within 270 days of receipt of the request."* (Highwood Emissions Management blog)

The current draft off the APCD new rule making leans towards the non-prescriptive approach but leaves open the question of how to "certify" new technologies for measuring methane emissions. The state does not really want to take on this task and is looking for a federal or industry group to play this role.



New Rule Making on measurement-informed methane intensity verification factors

The purpose of this research paper is to discuss the challenges and opportunities that come with a ‘measurement-informed inventory’ approach and to identify and discuss the new changes being asked of operators and regulators with this new approach. In our opinion the agency is making an important step in incorporating measurements to the estimation framework but it is not the final step in this journey. Our analogy is that we are all trying to learn how to swim (eliminate methane emissions) and with this new rule making we are stepping out of the shallow end of the pool and are entering the deep end.

According to the new proposed rule:

“Operators must follow one of the following methods for verifying methane emissions and ensuring GHG emission calculations are accurate in the reported intensities of the operator’s greenhouse gas annual inventory.

1) Colorado Derived Intensity Verification Process

On an annual basis, beginning in December 2024, the division will publish one or more intensity verification factors that operators must use for calculating GHG intensity for their operations, as required by Regulation 22, Part B, Section IV. These factors will be appropriate for use by all facilities within a basin or may be facility-specific as defined by specific facility prototypes. The division will publish data used to calculate the factor(s) and the factor(s) themselves. The division will calculate either basin-wide or facility-specific intensity verification factors using the following methodologies.

The intensity verification factor(s) will be applied to the methane emissions reported in ONGAEIR to account for under or unreported emissions. The methane intensity verification factor cannot be less than 1.0 (this assumes that there are no cases of over-reporting using the traditional engineering factors methodology). If the methane intensity verification factor calculation results in a number below 1.0, the intensity verification factor will revert to 1.0. All greenhouse gas emissions reported in ONGAEIR will also be included in the calculation of GHG intensity.

2) Operator Specific Intensity Verification Process

The division recognizes that many operators are already taking additional steps to deploy methane detection technology through improved monitoring efforts. Operators are also using the expanding technology of methane sensing to ensure emissions are measurement verified where the emissions are 1) reported to a regulatory agency or 2) publicly disclosed. (See discussion of the digital canopy).

Instead of using the Colorado-derived intensity verification factor, operators may demonstrate they are meeting the requirements for use of a measurement-informed inventory by developing an intensity verification protocol that requires both methane measurements and robust auditing provisions. Operators must implement the protocol every year where the operator does not use the Colorado derived intensity verification factor to calculate GHG intensity.

At a minimum, an operator's intensity verification protocol must contain the following items:

- The methodology the operator will use to derive total methane flux from each facility. The division defines total methane flux as all methane emissions, irrespective of the cause.
- The annual documentation and record retention practices that the operator will follow, including transparent records retention practices for activities that may affect emissions rates.
- The identification of technology the operator will use to verify annual emissions and how the operator will apply the technology at the facility level.
- The sampling strategy the operator will use to inform emissions modeling and calculations
- The process to account for all methane releases in annual emissions inventories, including those that are intermittent
- A protocol to verify methane emissions from facilities acquired by the operator within the calendar year
- Documentation of any revisions to the protocol

Operators must identify how they intend to comply with the measurement-informed inventory requirements in the GHG intensity plan required by Regulation 22 Part B Section IV.E intensity verification protocols created in accordance with Section 2 of this guidance are subject to division review and approval. The GHG intensity plan, and its derivatives, should be auditable and reasonably assured by a third party.”

The rules are changing at the federal level as well.

The US Methane Emissions Reduction Action Plan of November 2022, plans to reduce methane emissions from covered sources, equipment and operations in the oil and gas industry by 75% by 2030. As part of the new plan, the EPA proposed new rules would, for the first time, implement nationwide reduction requirements for both new and existing sources. The EPA's proposal is based on 2014 guidelines passed in Colorado, the first state to regulate methane emissions in the oil and gas industry.

Let us return to the new APCD rule proposal for more details on how the state and federal rule will align.

“The division also recognizes that many governments, non-governmental organizations, industry coalitions, and international bodies are working toward improving GHG emission inventories through protocols that require a methane measurement informed inventory. This protocol will provide alternate options for operators to follow, to validate their state-wide methane emissions and intensities reported to the CDPHE. These options would align with developed protocols, but require a minimum level of compliance.”

Reduction of oil and gas sector emissions depends of an accurate understanding of the routine sources of emissions and the frequency, distribution and magnitudes of emissions events that occur at oil and gas facilities. Several recent studies suggest that existing reporting of GHG inventories based on a formula of engineering factors underestimate the oil and gas sector's contribution to methane emissions and that distributions of emissions are highly skewed toward a tail of major but infrequent events. Further studies indicate that a significant percentage of the under-reported emissions exists because current inventory methods miss reporting

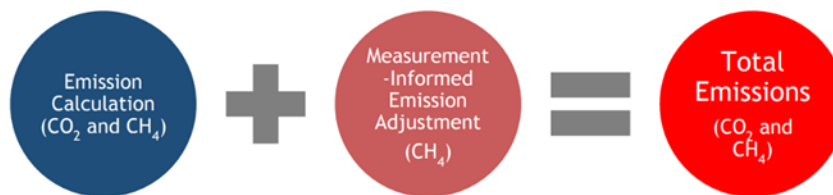
emissions that occur during abnormal operating conditions (venting and flaring being two examples, equipment or pipeline blow-down is another). The division will require the oil and gas sector's more accurate GHG emissions inventory to ensure Colorado is on track to meet established GHG reduction targets and verify GHG intensities reported by operators.

To improve and verify the accuracy of the GHG emissions calculations in the Oil and Gas Annual Emissions Inventory Reporting database (ONGAEIR), operators must use a measurement-informed inventory of GHG emissions. To achieve a measurement-informed inventory, the division has two goals: “to improve the bottom-up calculation methodologies for all greenhouse gas pollutants and to account for unreported methane emissions as measured on regional or site level.” <https://cdphe.colorado.gov/oil-and-gas-greenhouse-gas-stakeholder-process> .

Measurement-informed inventory

What does measurement-informed mean?

- Using emission or parametric measurements at a regional or facility or equipment level to INFORM emission calculations



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But what is a measurement-informed inventory? The current inventory comes from the EPA Quad0a guidelines. EPA finalized in 2016 the New Source Performance Standards (“NSPS”) for volatile organic compounds (“VOCs”) and methane emissions from the oil and gas sector. This rule is commonly called the “Quad Oa” rule, which refers to its place at 40 C.F.R. Part 60, Subpart OOOOa. Before then, EPA had regulated only VOCs from the sector, and because VOCs and methane both come from natural gas leaks, the previous regulations finalized in 2012 (known as “Quad O”) had the effect of also limiting methane emissions.

Quad O and Quad Oa apply only to “affected sources” that are new, modified, or reconstructed after the rule’s effective dates. They do not apply to any of these sources that existed before those dates. As a result, these rules govern only a fraction of sites and equipment used in oil and gas operations.

Again, going back to the proposed rule, here is what the state means by this new approach.

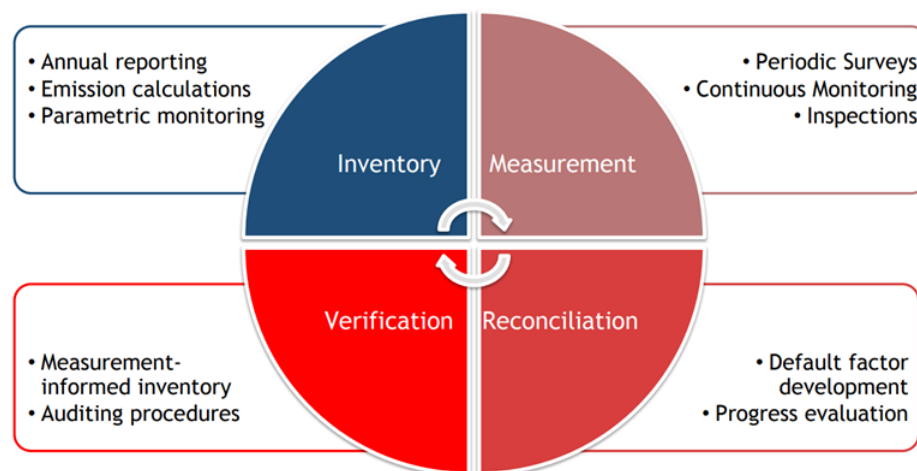
“To qualify for the Operator Specific Intensity Verification Process of this guidance, operators must utilize measurement technology to inform emissions reported in ONGAEIR. The goal is to improve accuracy, thoroughness, and confidence in reported emissions. The division refers to this approach as a measurement-informed inventory (MII).

Because the methane detection and measurement world are evolving, the division cannot provide a complete set of decision points for operators to consider. Instead, operators should consult their current strategies and relevant guidance to develop a measurement-informed intensity verification process most applicable to their operations.

When incorporating measurement into the annual emissions inventory process, operators must consider the following:

- **Technology:** Operators must determine the most applicable screening methods and whether to include additional methods like fly-overs or onsite continuous monitoring
- **Measurement or detection:** Measurement of methane emissions (i.e., quantification) or detection of emissions (i.e., frequency and duration) to inform engineering calculations
- **Parametric monitoring:** Where measurement of emissions is not feasible, other parameters may influence emission calculations if calibrated appropriately
- **Frequency of measurement:** Some measurement options will benefit from more frequent monitoring
- **Statistically significant monitoring strategy:** Many measurement verification methods do not require monitoring at every facility, but instead at a statistically significant portion of facilities to inform emissions calculations of all facilities
- **Monitoring strategy:** Operators need to consider how best to conduct monitoring across the range of operations to best capture unpredictable events. Any monitoring strategy must account for the variable and transient nature of oil and gas emissions, and any assumptions about facility-type emissions profiles must be documented and validated
- **Uncertainty:** Operators need to consider and disclose uncertainty in calculations and the method of measurement (refer to the two CSU papers by Bell et al for comments on this element)
- **Emissions Materiality at Facility Level:** Operators need to consider source level emissions and determine which emission should be considered materially relevant to the emission(s) profile
- **Reconciliation Process:** Operators must disclose where and how emission measurements are used to improve engineering calculations.”

Annual Verification Cycle



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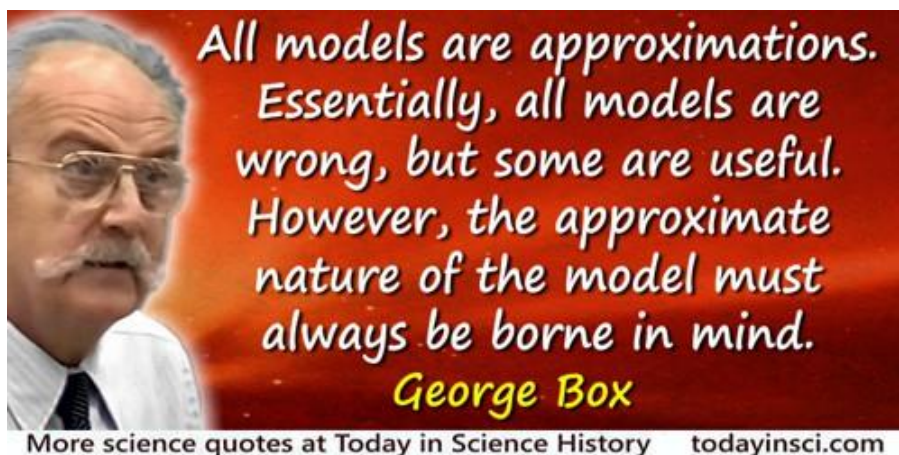
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Despite technology advances, policy can get way ahead of the application, leaving some operators ahead of the regulations while others are struggling to catch up. With this language the state regulatory agency is throwing the ball back in the operators' court to demonstrate the feasibility of the technology they select if they go the route of the Operator Specific Intensity Verification Process.

Is Colorado moving too fast with implementing the new rules relying on emerging technology and new operations designs and procedures or is it moving too slow to impact climate change plans and to allow regulations to drive innovation? The new rules will be effective only so far as industry and regulators are able

to implement them. The next few years will likely tell us if the regulators and the industry are ready and capable to make this move. Conservative operators may wait and let the state take the lead and see if they can live with the Colorado Derived Intensity Verification Process and the new EPA methane fee. While leading operators will not delay their new technology investments and focus on helping their LDAR methods. The objective of those technologies and operation practices are to identify and locate leaks to maintain production levels, not produce better annual reports. A key milestone will be the first date (2025) when the state will measure progress against the Energy Office's roadmap. As the first year the new rule making is in affect is 2024, there is not going to be a lot of time to adjust course.

"I don't think -- and my experience tells me -- that regulatory authorities have any idea of how much methane is going into the atmosphere. It's just an estimate. "And I guarantee you, it's an underestimate." – Tim Doty, former senior regulator for the Texas Commission for Environmental Quality.



Setting a trusted baseline and reporting rule is not an easy task.

Feedback from several stakeholders in the public comment process suggest that the proposed top-down aerial measurement approach is still in the science evaluation or pilot stage and not ready for a legal compliance application. They urge the APCD to invest in more research related studies (maybe funded by Colorado's **Air Quality Enterprise**) *“until such time as a method has been thoroughly developed, peer-reviewed; includes and accounting for and mitigation of measurement bias, errors and uncertainty; and can be implemented routinely in the required timeframes for compliance.”* (Response from Weld County, 2022)

In the end the measurement-informed inventory and state-wide methane verification factor are still just estimates, probably a better estimate than we have today, but still an estimate. The devil's in the details. The problem is not that we do not have an accepted way of measuring and reporting methane emissions. The problem is that we have too many ways to do that and the technology is advancing every year, providing more alternatives not fewer. How will the Air Pollution Control Division pick the right technology options (or qualify specific measurement technologies and suppliers and verify results). Although the Division has received additional funding and is working to increase its staff, how will the limited resources in the Division oversee the operator specific intensity verification processes? Will measurements help develop a common understanding or be a source of more divisive debate?

Measurement Matters, not Estimates

But measurements are not a silver bullet and new technologies are not magic. It is important to understand the limitations of the term “measurement” in the context of the tools available and the field conditions experienced.

Detecting, assessing, and quantifying methane emissions in the field does not occur with the precision that may be implied by the term measurement.

Emissions detection is statistical and probabilistic in nature. This means that a technology might detect a leak of a given size (say the EPA proposal of 10/kg/hr) one time and miss a leak of similar size the next survey. The problem is, lacking anything more than a target emissions rate, there is no way to know how likely it is that the technology would detect a leak in a given survey and therefore no way to assess the emissions reduction potential of the technology. To enable such assessment, the regulator needs to know whether leaks of a given size were detected with high confidence (say >90% probability of detection), whether leaks of that size were statistically detected half of the time (50% probability of detection), or whether there was negligible likelihood (say <1% probability of detection) of detecting leaks of the target magnitude. To remove this ambiguity, regulations should require the detection sensitivity value to be combined with a probability of detection, sometimes referred to as PoD. (Bridger Photonic comments on proposed EPA rule).

In oil and gas operations, the sources of methane emissions are dispersed, unlike those of CO₂ emissions, which tend to be concentrated at single source points. Technologies that identify and quantify methane emissions rarely take measurements at the actual source of emissions. Instead, most quantitative approaches take short snapshot measurements of atmospheric concentrations at specific points above or downwind of a facility or group of facilities. An emissions rate is then inferred using a model that accounts for wind speed and direction, background concentration and plume shape, which are typically estimated and not measured. This approach has inherent uncertainty based on the measurement device, the meteorological modeling, and the representativeness of the measurement at that point in time compared to annual emissions. (White, et al, 2018)

Accurately determining the volume of methane emissions in an operating environment can be challenging as well due to the variety of sources and the variability of conditions in which they occur. Factors affecting accuracy include frequent changes in local wind direction and speed, accessibility of the emissions source and variability in emissions rate that can dramatically affect quantification depending on the time at which the event is observed. The tools used to evaluate an emissions event have error bars for a single “measurement” ranging from +/- 17% at the most accurate to +/- 70% for the types of events that occur in the field.

Methane emissions can have a wide range of potential causes, such as vents in older facility designs or upset conditions at a well site. Regular monitoring can help operators detect and mitigate infrequent super-emitters; a term used to describe sources of large emissions volumes. But the debate is now what does “regular monitoring” mean in practical terms. It probably is not a one-size-fits-all solution.

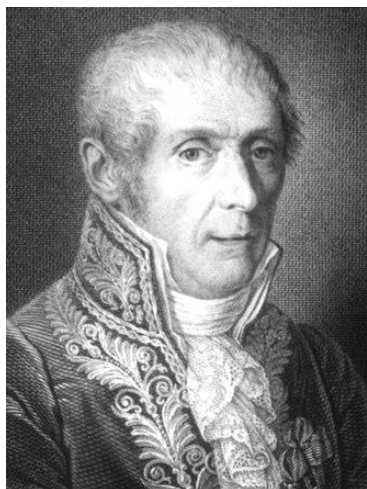
Efforts to minimize error include the gathering of localized weather observations, increased sampling frequency, optimizing the distance from the emissions source and refining algorithms that process data. Selection of the sensor type for specific field conditions is also an important consideration. The resulting science-based estimates are better characterized as quantification rather than measurement, recognizing they are a more accurate and scientific approach than an emissions factor but fail to provide a consistent, or repeatable measurement of an emissions event.

Within the upstream oil and gas sector, methane is primarily emitted from five categories of sources

- **Vents** are direct releases to the atmosphere from equipment or processes in the natural gas value chain. Often these releases are approved in the operating permit
- **Fugitive emissions and equipment leaks** are unintentional sources of emissions from components such as valves, flanges, seals, piping, and other equipment
- **Flaring** can be utilized to burn excess gas to relieve pressure in an upset conditions of when sending gas to sales is impossible. When flares combust natural gas, most of the methane is converted to CO₂

but typically 2% of methane remains un-combusted under ideal flare performance. Routing flaring is not permitted in Colorado.

- **Combustion of natural gas** occurs in equipment to meet operational energy needs like electricity or heat. Some un-combusted methane will be part of the exhaust stream but the expected amount varies with the type of combustion equipment
- **Permitted emissions** such as blow down operations where the release of gas from processing equipment or pipelines to the atmosphere in order to relieve pressure so that maintenance, testing or other activities can take place.



“In November 1776, methane was first scientifically identified by Italian physicist Alessandro Volta in the marshes of Lake Maggiore straddling Italy and Switzerland. Volta was inspired to search for the substance after reading a paper written by Benjamin Franklin about "flammable air". Volta collected the gas rising from the marsh, and by 1778 had isolated pure methane. He also demonstrated that the gas could be ignited with an electric spark. Following the Felling mine disaster of 1812 in which 92 men perished, Sir Humphry Davy established that the feared firedamp was in fact largely methane. The name "methane" was coined in 1866 by the German chemist August Wilhelm von Hofmann. The name was derived from methanol.” <https://en.wikipedia.org/wiki/Methane>

Making the invisible, visible

Current detection and measurement technologies provide a wide-range of levels of precisions (detection threshold) and functionality including how often they sample (temporal sampling) and what area is measured (spatial sampling). Many operators in the industry are experimenting with different methods to learn what works best and what types of methods are most affordable for their assets. Measurements do not come free so operators will be concerned with the value of information versus the cost to record that information.

Regulations should not be too prescriptive at this stage of rapidly emerging technologies in order not to enshrine legacy approaches into law or penalize the applications of new methods. Regulations should set the targets and let the operators figure out the best way to get there. Key methods in use today include:

- **Emission factors** provide an estimate of the average emissions for an activity or piece of equipment. Combining emissions factors with facility or asset-specific information can identify the main source of emissions resulting from the way a facility was designed and is being operated.
- **Operational information** – data such as temperature or pressure readings collected through a process instrumentation and control systems (like SCADA) can help interpret detection results. Leading operators are developing algorithms to predict trends and identify when to adjust facility operating conditions to prevent emissions events

- **Source-level measurements** – fixed metering can provide granular information about emissions rates for individual pieces of equipment, and manual methods like optical gas imaging (OGI) can help pinpoint leaks and initiate repairs and maintenance. This can improve inventory accuracy, but may be challenging to scale across a company’s full portfolio of assets
- **Site-level measurement** – facility scale advanced technologies deployed on planes, satellites or drones can provide an efficient way to detect the general location of a leak or whether a piece of equipment is missing from the operator’s inventory. The spatial and temporal resolution from these “top-down” measurement is improving at a significant rate.
- **Top-down measurements** from satellites or aircraft Methane measurements taken at spatial scales greater than the equipment scale. Typical top-down measurement scales include site, region, and basin. In the production segment, net emissions from a spatially distinct set of equipment, such as a well-pad, a compressor station, or a central processing facility, or from a set of such facilities. Top-down measurements can also include linear assets such as pipelines, when a pipeline is examined

Tools for Detection and Quantification

Methane detection and quantification tools typically consist of a sensor that detects methane in the atmosphere, additional data collection (such as temperature, humidity, and wind conditions), and proprietary algorithms that process the data to provide quantification through inference. There are various types of sensors that can be used for methane detection, including Tunable Diode Laser Absorption Spectroscopy (TDLAS), Metal Oxide Sensors (MOX), Short Wave Infrared (SWIR), Light Detection and Ranging (LiDAR), Optical Gas Imaging (OGI), Cavity Ring Down Spectroscopy, and others. Each sensor type has limitations that can introduce error. The need for additional data and the quality of proprietary analytics also impacts results.

Each sensor type has strengths and limitations, and can be deployed in different ways, such as through handheld instruments, mobile platforms like vehicles, drones, or satellites, or as fixed sensors. Some sensors require external light, while others have an internal light source. Some sensors require wind to function properly, while others may not work in windy conditions. Background conditions can also affect the accuracy of optical systems. Leading technology providers are working to improve the accuracy and reliability of methane detection tools through more frequent observations, improved light sources, enhanced signal processing, and refinement of proprietary algorithms. These efforts aim to increase the probability of detection at lower detection limits and improve quantification while considering economic factors. However, even with improvement the results will not achieve the level of accuracy and repeatability characterizing the concept of direct accurate measurements.

Nowhere to Hide, No Reason to Hide

In our opinion the highest priority reason why operators use measurement techniques to identify, locate and quantify methane and other greenhouse emissions is to stop and fix the leak faster and keep more natural gas product in the sales pipeline. A valid secondary reason for measurement is to improve inventory reporting results. State and federal agencies are focused on the second result, not the first.

Methane is rapidly becoming a top priority for remote monitoring given its warming potency and lack of good data. Currently, various monitoring technologies are used, including sensors on satellites, planes, drones, and ground-based sensors. Ground-based sensors provide more frequent and localized measurements than other technologies, but they can be difficult to deploy over a wide area. Satellite-based sensors have significant potential because of their extensive, global reach, but as of now, they are unable to produce highly localized observations (source-level).

Recent studies from aircraft and satellites suggest that GHG emissions are larger than previously thought. The outsized role of intermittent point source emissions has been demonstrated by multiple studies of the Permian

Basin. (Chen et al 2022 and Cusworth et al 2022) Researchers utilizing the Sentinel 5 satellite and others has detected “ultra-emitters” mainly in the Middle East, Central Asia, Russia, and the United States. Similar analyses have been conducted by researchers at the Payne Institute at the Colorado School of Mines utilizing TROPOMI data. Though somewhat coarse (pixel size 7x5.5 km), to make the data more useful, these researchers have developed a statistical model to estimate the underlying methane field at a higher resolution than the observations provided by TROPOMI. New satellites will detect methane at far higher resolutions and will thus be able to locate sources with greater precision. (Dunn and Bazilian, 2022)

The use of satellite imaging to verify self-reporting of methane emissions using empirical data gathered in near-real time by artificial intelligence, could cost the fossil fuel industry dearly in fines under the new methane provisions of the US Inflation Reduction Act (IRA). The IRA requires the US Environmental Protection Agency (EPA) to adopt within two years methods to monitor and collect empirical data on methane emissions. The act introduces the federal government’s first-ever tax on greenhouse gas emissions, but does not specify preferred technologies.

Satellite monitoring is assumed to be at the top of the list, according to geo-analytics company Kayrros. Private industry can, and likely will, play the same game, as it has access to the same technologies the government uses and can invest to acquire empirical data to identify problems companies might not even know they have. Once emissions are quantified at their source, industry can clean up supply chains and thus blunt the financial impact of penalties set to debut in 2024.

The new law calls for fees of \$900 per ton of methane by 2024, rising to \$1,500 by 2026 (equating to \$36 and \$60 per metric ton of carbon dioxide equivalent, respectively). Based on current emissions data, Kayrros analysts calculated that total costs imposed on the industry could exceed \$1.25 billion in 2024, rising threefold by 2026, to \$3.3 billion, if no preventative or mitigation measures are taken. But this is too large a penalty to ignore. Many production companies are taking steps to understand and lower their emissions.

What will the state do with all the new data from self-reporting operators?

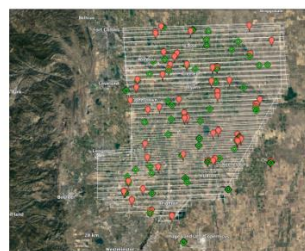
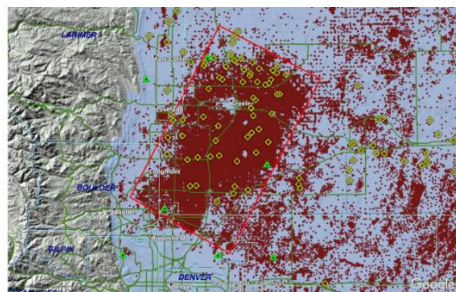
Colorado Department of Public Health and Environment took to the skies in July, 2021, completing the state’s first airborne survey designed to monitor for methane and other emissions at major oil and gas sites in the Denver-Julesburg Basin. The initial flight is the first of many scheduled for 2021. The aerial surveys focused on areas north and northwest of Denver in Boulder, Weld and Larimer counties. (ecos.org 2021)

The department’s aerial survey work has four phases, and the department is working with the University of Arizona, Colorado State University, Scientific Aviation (a private company based in Boulder), the University of Colorado, and the University of Maryland to design and fly these surveys. CDPHE and COGCC will also support the aerial work with ground monitoring and inspections to verify data and monitor emissions at smaller operations with the help of Colorado State University.

“We are committed to deploying advanced technology and the most capable tools to get a clear picture of methane and other emissions in the state,” said Shaun McGrath, CDPHE Director of Environmental Health & Protection. “The resulting data will inform how we approach regulating oil and gas operations and other emitting sites in Colorado.”

1a. CarbonMapper Aerial Surveys

- ▶ Hyperspectral Spectroscopic Plume Imaging
 - Partial Detection range ~10-100 kg/h
 - Further investigation with Stanford Controlled Release Expts.
- ▶ Coordinated DJ campaign in Summer and Fall 2021
 - Two weeks each
 - Focused on Densest production regions of Basin. Included other sources Feedlots, Wastewater, Landfills
 - Supplementary TROPOMI/STILT inversions for regional quantification
- ▶ Smaller Piceance Campaign in Fall 2022
 - 5 Flight days, 19 O&G Sources



3/2/2023

O&G Intensity Verification Technical Meeting



15

The state is funding the aerial surveys with money from a settlement between the Colorado Oil and Gas Conservation Commission (COGCC) and Kerr McGee that was related to the 2017 explosion in Firestone. This survey was the department's first flight — CDPHE used the flight to both gather data on methane emissions and prepare for a larger concentrated aerial survey effort in September and October, 2021.

Through the public comment sessions, several stakeholders have cautioned the APCD not to overcommit on complex aerial monitoring projects. From data acquisition, to data processing and public release of results, the state may not yet have all the capabilities and process to follow through on top-down aerial or satellite measurement studies in a timely manner. Some of these technologies may be in “research” rather than a “compliance” state of maturity.

The phase one data set from the 2019 flyover of the Denver-Julesburg Basin is included in a research report (Cusworth, et al, 2022) that included data from several basins (San Joaquin Valley, Unita, Denver-Julesburg, Permian and Marcellus) by researchers from University of Arizona, Carbon Mapper, Jet Propulsion Laboratory, Arizona State University and Environmental Defense Fund. In the conclusion of that study the authors concluded: “*No single instrument, measurement platform, or network is capable of full characterization of CH₄ emissions within a basin or region. Therefore, tiered observing systems are needed to adequately constrain emission budgets and prioritize areas and infrastructure for mitigation.*” It seems like the APCD is on the right track but the ultimate answer still lies in integrating all the data measurements into a digital canopy. But many other stakeholders do not believe we have the time to wait for additional studies. They demand answers now.

In 2022, the state legislature appropriated an additional seven million dollars for a three-year aerial monitoring survey program to collect more data and to help the agency learn how to use the new top-down measurements. Of course, these types of surveys gather data on emissions from more than oil and gas producing sites, including from agriculture and landfill sites which are significant sources of greenhouse gas emissions as well. The Air Pollution Quality Division is also looking at satellite monitoring as a potential way of developing the top-down perspective and identifying an estimate of the unreported emissions.

Be Careful with Quantification

The Energy Institute at Colorado State University, using the METEC facility, have recently published two important studies conducting single-blind, controlled testing of both airborne and continuous monitoring

solutions for methane detection. Useful technology exists and is improving rapidly but relying on current measurement techniques to produce precise methane emissions results may still be beyond current technologies at this stage.

Other projects are pursuing the same or similar goals of controlled testing of methane measurement technologies to gain a better understanding of measurement precision and accuracy of emerging monitoring solutions. They include Allen et al (2020), Bell et al (2020), Brantley et al (2014) and Fox et al (2021) for mobile measurement systems, Corbett and Smith (2022) for TDLAS unmanned aircraft surveys, Heltzel et al (2022), Ravikumar et al (2019) for Stanford/EDF Mobile Monitoring Challenge, Singh et al (2021) for Alberta Methane Field Challenge, Torres et al (2022) for low-cost sensors, and Tullos et al (2021) for short duration measurements. These studies represent an important check on just how well emerging measurement solutions provide an answer about methane emissions we can trust.

Here are a couple of key insights from the authors of the CSU studies.

“While the importance of mitigating methane emissions is well recognized, measuring these emissions from natural gas facilities remains a challenge, due to the vast extent of natural gas supply chain and the temporal variability of emission sources.” ... “Key advantages of continuous monitoring (CM) solutions include providing temporally resolved data, potentially quantifying emissions over extended periods, and by detecting large fugitive sources sooner than they otherwise would be detected. However, the performance of continuous monitoring solutions is poorly understood, including the solutions' detection limits, quantification accuracy, and temporal resolution, which are all impacted by meteorological conditions, sensor placement and, other factors. A better understanding of continuous monitoring solution performance is required before using data from these systems to enhance or replace existing emission inventories, particularly if the resulting inventory will be used as part of alternative compliance programs or as the basis for enhanced leak detection and repair (LDAR) programs.”

“The large variability in performance between continuous monitoring solutions, coupled with highly uncertain detection, detection limit, and quantification results, indicate that the performance of individual continuous monitoring solutions should be well understood before relying on results for internal emissions mitigation programs or regulatory reporting. Additionally, given the rapid development of these solutions, additional implementation standards and regular testing will also be necessary.”

“Simulation results suggests that using quantification estimates from CM solutions for measurement-based inventories may substantially misstate both the number of emitters and emission rate, and these estimates should be used with caution until both detection limits and emission rate accuracy are improved and uncertainties are better characterized.”

“The performance of CM solutions has changed substantially; testing has also increased in rigor. Concomitantly, the stakes for next-generation leak detection and quantification solutions have also risen dramatically, as more organizations consider adopting results from these solutions into programs ranging from company-internal emissions mitigation reports to regulatory programs with financial penalties. These rapid and dramatic changes drive a need for quality testing, critical review of solution performance, and a clear understanding of uncertainties for all result types reported by these methods.”

“The results presented here indicate that users should utilize CM solutions with caution. Detection limits, probability of detection, localization, and quantification may or may not be fit-for-purpose for any given application. If performance is clearly understood, and uncertainties are robustly considered, the solutions tested here, as a group, provide useful information. For example, most will detect large emitters at high probability and sooner than survey methods, and will quantify those emitters well enough to inform the urgency of a field response. In contrast, relying on quantification estimates from these solutions for emissions reporting is likely premature at this point.” – (Bell, et al, 2022)

So we are making progress but we have not reached the measurement finishing line yet!

Verification Matters

With the general public and the environmental movement lack of understanding or trusting operators self-reporting of emissions, there is a call for independent third-party verification of emissions reporting. That leads to the question of what is the difference between auditing and verification?

Auditing is defined as the on-site verification activity, such as inspection or examination, of a process or quality system, to ensure compliance to requirements. An audit can apply to an entire organization or might be specific to a function, process, or production step. Some audits have special administrative purposes, such as auditing documents, risk, or performance, or following up on completed corrective actions. <https://asq.org/quality-resources/auditing>

MiQ, a methane emissions standard, defines an independent auditor as one that is independent of operator, the information audited, the certification authority, and which has no financial or reputational interest in the outcome of the audit. To ensure rigorous audit practices concerning an audit standard, MiQ administers an accreditation process to ensure that auditors meet minimum requirements which include, but are not limited to:

- Familiarity with standards of quality management for environmental systems
- Bottom-up emissions inventory development
- Competency regarding the operational and quantitative use of emerging top-down and bottom-up measurement methods on various oil and gas facilities
- Air emissions control, air quality, operational and general process engineering expertise within oil and gas industry
- Experience providing professional environmental auditing services

This lays out the criteria for a rigorous auditing process. But one question is that if the APCD adopted this standard, are there enough qualified auditors to oversee 100% of all the oil and gas facilities in Colorado?

For current regulatory compliance demand, there probably are an adequate number of qualified auditors who are experienced in benchmarking a company's Environmental Management Systems, reporting strategies, calculation methodologies, measurement methodologies, and levels of reporting responsibilities (and ownership). Colorado operators have worked with a variety of firms and individuals and rely on their audit process. However, the sheer volume of day-to-day work that is will be required of Colorado operators with new rules poses fresh challenges to finding trained and qualified workforce for all sub-disciplines in the air space.

On the federal front, the Environmental Protection Agency is expected to see a surge in funding under the federal infrastructure law and the Inflation Reduction Act, but resources are and likely will remain stretched thin due to understaffing and a busy regulatory agenda. EPA Chief of Staff Dan Utech noted, however, that *"the agency is moving further and faster than ever before"* even as it grapples with *"depleted staffing levels, persistent funding challenges and a previous administration that left the agency neglected and scientifically compromised."*

Even if this is the right direction, are we trying to move too fast? How do we speed up all the capabilities from all the stakeholders to accelerate methane emissions?



If one standard is good, then dozens of standards must be better, right? The figure above shows many but not all of the current efforts in developing reporting standards for environmental performance. Global corporate sustainability can get lost in the multiple layers of voluntary frameworks. When deciding on the transformation, the key ingredients are leadership and strategy, backed up by the operational infrastructure.

What is verification? To verify something is to make sure it is correct or true, so verification is an action that establishes the truth of something. Checking an ID is a verification of your age. Your bank will often ask for part of your social security number as verification of your identity. Scientists do research to establish verification for their theories. In all cases, verification is like a stamp of approval. <https://www.vocabulary.com/dictionary/verification>

There has been some feedback that the APCD needs to develop their own verification method and not rely on existing external approaches. That adds to the needed capability for an agency already stretched by these new regulations. Some operators have made commitments to align their production plans to commercial verification models like the OGMP 2.0 framework, the MiQ approach, the Project Canary Trustwell, the GTI Veritas protocol or the Equitable Origin framework and there are others under development. Each has benefits but each are focused on a slightly different goal than the state's verification of methane emissions reporting rule.

How many standards will oil and gas operators be asked to comply with? They already must navigate the "patchwork" of regulations between the federal government and different state regulatory frameworks. They have similar goals but each method has a different way of getting there.

"Sourcing, measuring, and verifying methane emissions from a myriad of operational processes and associated equipment that are used throughout the value chain is costly and bears significant uncertainty. The ability of regulatory bodies to enforce rapid curtailment of methane emissions is also limited due to certain constraints including the private ownership of relevant data, the global nature of the issue and preserving the overall competitiveness of the industry. Existing certification programs offer market-based incentives to facility operators in various segments of the supply chain. Consumers' willingness to pay for products with environmental attributes,

along with investors' concerns about environmental and regulatory risks, has allowed for the creation of a market mechanism to reward methane emissions management and other ESG metric.” (Garp, et al 2023)

What is a Verification Protocol?

Back to the proposed rule-making draft, “*The Oil and Gas Methane Intensity Verification Protocol provides current Air Pollution Control Division Instruction for verifying reported methane emissions and calculated greenhouse gas (GHG) intensities required by Regulation 22, Part B, Sections IV.E.4 and IV.F.*

Reduction of oil and gas sector emissions depends on an accurate understanding of the routine sources of emissions and the frequency, distribution and magnitudes of emission events that occur at oil and gas facilities. Several recent studies suggest that GHG inventories underestimate the oil and gas sector’s contribution to methane emissions and that distributions of emissions are highly skewed, where a handful of sources represent the majority of GHG emissions. Further, studies indicate that a significant portion of the discrepancy exist because current inventory methods miss emissions that occur during abnormal operating conditions. The division requires the oil and gas sector’s most accurate GHG emissions inventory to ensure Colorado is on track to meet established GHG reduction targets and verify GHG intensities reported by operators.

To improve and verify the accuracy of GHG emission calculations in the Oil and Gas Annual Emissions Inventory Reporting database (ONGAEIR), operators must use a measurement-informed inventory of GHG emissions. To achieve a measurement-informed inventory, the division has two goals: to improve the bottom-up calculation methodologies for all greenhouse gas pollutants and to account for unreported methane emissions as measured at a regional or site level.”

There are two verification protocols mentioned in the draft rule by APCD: OGMP 2.0 and GTI Veritas. Let us learn a little more about each of them.

OGMP 2.0 Framework

The OGMP program was originally formed at the UN Secretary General's September 2014 Climate Summit in New York and includes member companies with assets representing some 30% of global oil and gas production. The group includes NGOs, along with government members including the UK, the Netherlands, Belgium, Spain, France, and Italy – all significant import markets for US LNG.

The Climate and Clean Air Coalition (CCAC), Mineral Methane Initiative (MMI), and the United Nations Environment Programme (UNEP), launched the Oil and Gas Methane Partnership (OGMP) as a voluntary initiative to assist businesses in cutting back on methane emissions. The UN Secretary-Climate General's Summit in 2014 marked the beginning of this initiative. Quite a bit has changed in the methane world in the intervening years, with many companies having set Oil and Gas Climate Initiative-wide targets for the intensity of their collective methane emissions. In addition to disclosing their unmitigated core source methane emissions under the current OGMP reporting framework, companies are not required to reveal the actual performance of those emissions. Stakeholders will force this shift as they become increasingly concerned with how well companies meet methane emission targets.

The OGMP 2.0 Reporting Framework revises the existing OGMP reporting framework to enhance the credibility of the methane reporting process and promote a better understanding of methane emissions across the oil and gas segments. As a result, current non-members will be encouraged to participate in the OGMP. OGMP reporting is essential for promoting mitigation efforts and accurately tracking progress towards goals. Maintaining a close link between the reporting framework and strategic action is critical. Generally, the framework provides a standardized and open reporting protocol, making it possible for stakeholders to accurately distinguish market leaders from laggards. The objective is to help the oil and gas sector achieve significant reductions in methane emissions over the next decade. The framework is a manner that is open and accountable to the public, governments, and investors.

This is a once-in-a-climate-generation opportunity to reduce methane emissions. The **Mineral Methane Initiative (MMI)** is committed to reducing methane and black carbon emissions throughout the entire mineral methane supply chain. For the industry, MMI has established median goals for reducing methane emissions, with the expectation that companies with better performance will set more aggressive goals. The Global Methane Alliance (GMA), the Methane Science Studies (MSS), and the OGMP collaborate to achieve these goals. Since mineral methane emissions frequently result from unplanned occurrences, it is difficult to quantify their quantity and distribution. Nevertheless, historic national submissions to the UNFCCC provide a pragmatic guide for assessing emission levels.

OGMP 2.0 allows companies to categorize their methane management and reporting journeys based on five distinct reporting levels. These levels are determined by: Reporting granularity at the source and geographical level, quantification methodologies, and uncertainty in the quantification. It is expected that companies will have various reporting levels for assets. This data will typically be treated as confidential and aggregated for external reporting.

- Level 1 (Venture or Asset Reporting)

The OGMP 2.0 requires a minor granular level of reporting to date at the country/venture/asset level. When it comes to operations and methane emissions, a company's reporting should stop at Level 1. For this purpose, high-level standard factors are often used to quantify emissions, which may assume that emissions for a given asset/venture are like those for a comparable one for which more data is available.

- Level 2 (Emissions Category)

OGMP 2.0 Level 2 reporting includes five categories for methane emissions upstream: venting, fugitive losses, flaring (energy or combustion), and other or unspecified emissions. There are three types of downstream and mid-stream losses: fugitive losses, connection leaks, and tightness failures. There are several sources of emissions, including venting (purging or venting for works, commissioning or decommissioning), regular emissions of technical devices, starts or stops, incidents, and incomplete combustion.

Source-specific reporting is required at the third, fourth, and fifth OGMP 2.0 reporting levels. At these tiers, you will find some of the most common and essential sources in the oil and gas industry. Widespread use of emerging site-level methane sensing technologies may prove unfeasible or impractical, even though these technologies are being developed to provide a comprehensive overview of reporting unit methane emissions representative of the entire reporting period.

- Level 3 (Generic Emission Source Level)

In order to estimate emissions at the asset level for level 3 OGMP reporting, emission factors (EFs) are used for all sources that are generic but source-specific. Several publications contain applicable EFs, including the OGMP Technical Guidance Documents, Natural Gas Star Program, etc. Although some of the generic emission factors referenced in the IPCC's "Tier 1 emission factors for fugitive emissions" may be relevant for quantification at OGMP reporting level 3, IPCC Tier 1 quantification does not require the same level of granularity needed by OGMP 2.0 reporting level 3. It is thus essential to note that OGMP 2.0 Reporting Level 3 is not directly comparable to IPCC Tier 1.

- Level 4 (Company Specific Emissions Source Level)

Source-level measurement and sampling can be utilized to determine relevant emissions factors (EFs) and activity factors (AFs) for this type of reporting. OGMP TGDs may refer to other sources-type-

specific quantification approaches (e.g., simulation tools and extensive engineering calculations) when necessary. In addition to operating assets, non-operated assets with an equity stake of more than 5% are also considered significant and are subject to reporting requirements.

- Level 5 (Site Level)

Additional site-level measurements are required for Level 5 reporting and Level 4 reporting. By using these measurements at the site level, discrepancies between source- and site-level emissions estimates can be resolved, thus strengthening the reliability of those estimates. In order to claim to report at level 5, the company must provide evidence of site-level measurement for a statistically representative sample of similar populations (within or across assets) for all relevant assets.

The timeframe for companies to achieve the OGMP 2.0 reporting requirements for the gold standard is three years for all operated ventures and five years for non-operated ventures. Reconciliation of Levels 4 and 5; The top-down measurements of site-level emissions are complemented by "bottom-up" reporting of source emissions (Level 4). Based on empirical measurement methods, level 5 incorporates top-down measures from a sample of facilities with bottom-up reporting from the sources. Through a third-party audit of reported emissions, investors will have greater confidence in the reliability of the data, increasing precision.

Compliant businesses will be provided with the necessary tools to provide credible evidence that they are contributing positively to climate change mitigation and meeting or exceeding their respective methane improvement goals and targets per the reporting standard considered to be the best in the industry. Those companies that fail to follow the credible path or report at levels 4/5 within the defined periods may lose their "gold standard" status. So far, 72 companies representing 30% of the world's oil and gas production have joined the Oil and Gas Methane Partnership 2.0 (OGMP).

GTI Veritas

Veritas, a GTI Energy Differentiated Gas Measurement and Verification Initiative, is designed to accelerate actions that reduce methane leakage from natural gas systems. The effort brings together scientists, academics, environmental organizations, certification organizations, and industry participants to demonstrate emissions reductions in a consistent, credible, and transparent way. The initiative will develop accurate and verified methane emissions intensities and the necessary protocols to calculate measurement-informed methane emissions for natural gas systems, by segment.

Veritas include five different protocols: methane intensity, measurement, verification, supply chain summation and audit and assurance. GTI is releasing their Veritas protocols publicly as open-source tools in February 2023.

On February 14, 2023, GTI Energy announced new open-source methane emissions measurement protocols to meet the urgent need to accurately measure and reduce methane emissions and accelerate the transition to a clean energy economy. GTI Energy's Veritas initiative is a set of standardized, science-based, technology-neutral, and measurement-informed protocols built to assemble methane emissions inventories that are verified by direct field measurements.

Starting in September 2021, GTI Energy, along with Highwood Emissions Management and SLR Consulting, convened dozens of industries, research, and environmental stakeholders to engage in a transparent protocol development process complete with diverse viewpoints and perspectives to enable credibility. More than 35 companies partnered with Veritas to shape the protocols' development.

The GTI Energy Veritas technical protocols cover six segments of the natural gas supply chain, including production, gathering and boosting, processing, transmission and storage, distribution, and liquefied natural gas. Protocols for each of the six supply chain segments include:

- **Methane Intensity:** Defines what methane intensities should look like for each segment of the natural gas supply chain.
- **Measurement:** Describes how to take measurements to inform emission inventories by segment.
- **Reconciliation:** Reconciles emission-factor inventories with actual measurements by segment.
- **Supply Chain Summation:** Adds multiple segments to reach a total emissions intensity.
- **Assurance:** Provides guidance for verifying an emissions inventory, company documentation requirements, and third-party auditing.

The design of the protocols is aimed at working together with existing methane reduction target frameworks and collaborations—empowering the industry with real-world technical solutions and consistent data to rapidly scale and accelerate methane emission reductions.

More than 25 companies are already using Veritas. By publishing these proven protocols and making them open source, GTI hopes to provide consistency and simplicity for companies dedicated to demonstrating their methane commitments. (GTI Veritas)

Research Proposal: Cost Benefit Analysis/ Value of Information Analysis

Whatever the measurement technology and practices and operator select, it will involve additional investment in both capital and labor. How will companies identify the practical and realizable value from such investment and how should they choose between the growing number of technology options available? One approach would be a **Value of Information** analysis. Some operators believe they have a target on their backs from regulators and from environmental groups. How can all stakeholders use this new measurement-informed methane emissions inventory to reach a common understanding of what is going on? (Tuffaha, 2020)

Value of information (VOI) analysis quantifies the expected value of research in reducing decision uncertainty to inform whether a decision can be made based on existing evidence or if additional evidence is required and worthwhile, (i.e., the new measurement of methane emissions). There is a range of VOI measures to inform research and reimbursement decisions. The most common measure is the **expected value of perfect information (EVPI)**, which is the value of additional information to resolve uncertainty in all decision parameters. Another measure is the **expected value of perfect parameter information (EVPPI)**, which estimates the value of resolving uncertainty in a parameter or a subset of parameters.

Both EVPI and EVPPI measure the maximum (i.e., upper bound) value of research, allowing for a rapid screening for the need and potential value of additional evidence. For instance, a negligible EVPI indicates that there is little value from additional research and a decision can be made based on existing evidence. However, if additional research is potentially worthwhile (i.e. EVPI is significant), the value of reducing uncertainty through collecting data in a study of a specific sample size can be estimated using the expected value of sample information (EVSI). By comparing the expected monetary benefits and costs of research studies, VOI analysis informs various types of decisions including

- reimbursement decisions to adopt, reject, or ask for additional evidence (e.g. coverage with evidence development),
- efficient trial design by selecting sample sizes that maximize monetary benefits and
- prioritizing research studies with the highest returns on research investments.

Despite the value of VOI analysis as a decision tool, its application in practice remains limited. The two main barriers against a wider VOI application have been the complexity of the calculations required to estimate VOI measures, especially the EVSI, and the lack of awareness among researchers and policy makers about this

approach. (Tuffha, H., Value of Information Analysis: Are We There Yet?, <https://link.springer.com/article/10.1007/s41669-020-00227-6#Sec3>)

So how do we proposed to use this analysis for our problem with measurement of methane emissions from oil and gas production activities? First, we need to define the objectives from the operators' perspective. They are the target audience for the tool. We still live in a market-based society so we propose that the existing equation of maximizing profits be the starting point. We recognize that the ultimate goal is reducing methane and other GHG emissions but for this analysis we chose to take pragmatic approach of trying to both make money and eliminate GHG emissions.

We start here: profits = revenue – costs. A very simple formulation but it will get more complicated soon. Revenue is calculated by production volumes times the commodity price (long term contract or short-term spot market). Since the product stream from oil and gas production consists of crude oil (valued at a market price minus penalties for viscosity and other undesirable components (like sulfur), natural gas liquids (sometimes called wet gas) and natural gas. There are other components that are not usually valued by the market like produced water, CO₂ and other inert gases like Nitrogen and Helium but we will classify these as costs to remove them from the sales stream. So here are our next formulas:

$$\text{Profits} = (\text{production volumes} \times \text{market price}) - \text{costs}$$

$$\text{Profits} = (\text{crude oil volumes} \times \text{commodity price} + \text{NGL volumes} \times \text{commodity price} + \text{natural gas volumes} \times \text{commodity price}) - \text{costs.}$$

Don't forget operating costs.

Now let us look at a tradition view of the cost element. Costs are usually divided into OPEX (operating cost of running the facility sometimes called LOE or lease operating expense and CAPEX (capital costs of drilling and completing the well and building the production facilities). Operating costs are measured in cost per barrel of oil equivalent (a way of bringing crude oil, NGL and natural gas volumes into one number) but capital costs are accounted for differently but reflected into profitability analysis through the financial concepts of DD&A (depreciation, depletion, and amortization). And don't forget taxes.

Capital depreciation refers to the decline in value of a capital asset. To give a simplified example, if a machine is bought for \$10,000 but only has a useful lifespan of five years, then every year, the value of this machine will decline by \$2,000. After three years, the machine is worth \$4,000.

Depletion is an accrual accounting method used to allocate the cost of extracting natural resources such as timber, minerals, and oil from the earth. When the costs associated with natural resource extraction have been capitalized, the expenses are systematically allocated across different time periods based upon the resources extracted.

Amortization is an accounting technique used to periodically lower the book value of a loan or an intangible asset over a set period. Concerning a loan, amortization focuses on spreading out loan payments over time. When applied to an asset, amortization is like depreciation.

Environmental Factors

The financial world that we live in today introduces some new value and cost elements into our VOI analysis. New sources of value from carbon (or methane) management include increasing gas volumes (as an operator reduces emissions, they capture more of the sales gas volume therefore increasing production volumes; carbon credits and taxes, and possibly a responsible gas premium.

According to the World Bank, there are two main cornerstones of carbon pricing: **emissions trading systems (ETS) and carbon taxes**. The first, also known as a cap-and-trade system, caps the total levels of carbon and other GHG emissions. It works as a system where caps are increasingly reduced every year and where businesses with low emissions can sell the allowances, they did not spend to others who spend more than they were allowed to. This creates the supply and demand of the carbon market.

On the other hand, **carbon taxes** set a direct price on carbon as they establish a tax rate on GHG emissions. Contrary to the cap-and-trade system, with carbon taxes, the emission reduction outcome is not pre-defined. Furthermore, there are also other indirect ways to price carbon such as taxing fossil fuels or removing fossil fuel subsidies. Trade policies where tariffs on solar or wind-generated electricity are reduced, or renewable portfolio standards where the electric grid must be a mix with a minimum share of clean energy, are also alternative ways of pushing carbon emissions out.

A **carbon credit** represents the right to emit a measured amount of GHG. Carbon credits work as a certification that business or individual owning them is counterbalancing the emission of greenhouse gases (GHG). In this way, the system of carbon credits works as a compensation method assuring a balance between GHG emissions and the respective amounts of certified mitigations. The ultimate purpose of carbon credits is, therefore, to reduce the emission of GHG into the atmosphere. In other words, carbon credits are exchanged in a carbon market, commonly referred to as the cap-and-trade market, where businesses can sell each other's rights to pollute. <https://youmatter.world/en/definition/definitions-carbon-price-carbon-credit/>

Responsibly-Sourced Gas (RSG), or Certified Gas is natural gas that has undergone independent third-party certification where molecules were produced under specified best practices for methane mitigation. One method for example, low methane certified gas, as well as other best practices around minimizing environmental and community impacts. This is important in this time as operators and buyers are seeking to differentiate molecules in response to market, community, and regulatory pressures. RSG can serve as an essential component of decarbonization and energy transition strategies. This helps to address the trilemma need for energy security, access to affordable energy, and cleaner commodities. RSG is assessed by a third party with its emissions (CH₄, GHGs, and CO₂e) profile measured and impact on other vital environmental categories (water and more) scored. <https://www.projectcanary.com/services/responsibly-sourced-gas/>

New cost elements include the cost of measuring the emissions. This might only be the purchase of new data or the service costs of an environmental/air quality contractor to run a survey (aircraft or drone) or the cost (opex or capex) of installing continuous monitoring equipment at the production facility. There are costs related to penalties, fines and deferred production related to violating permits issued by state or federal agencies.

There are other benefits that are difficult to quantify like brand reputation (good or bad), ESG rating to help with acquiring investments and the community license to operate elements that could mean the difference of obtaining a lease or permit and your good neighbor reputation to proactively deal with complaints and stay out of the courtroom.

We told you this was going to get more complicated. Commodity prices fluctuate on a minute-by-minute basis based on market demand but let's use current market prices for our product stream (see appendix for a deeper dive into the VoI decision risk analysis framework)

Pathways

We have developed six pathways to evaluate in our VOI decision tree. Each path could be the right one for an operator depending on their criteria for success but we will try to use them to analyze each of the elements described previously and maximize profits while minimizing the operations environmental footprint.

We will create a financial model from realistic economic parameters using both a Weld County DJ Basin Niobrara formation well and a Garfield County upper Cretaceous Mesaverde formation well. Can we find a win-win path through this maze of engineering, geologic, operations, economics, community engagement and regulations to do the right thing for the investors and the right think for the planet?

Pathway #1: minimum effort path, accept state default emissions factor and continue to use engineering factors inventory method

Pathway #2: Snapshot from top-down measurements, early warning alerts to improve LDAR response to leaks (Bridger Photonics)

Pathway #3: Continuous monitoring outside-the-fence with third-party verification (Project Canary)

Pathway #4: Integrate SCADA with emissions models, cloud platform for measurement, forecasting and reporting (MRV), continuous virtual well tests

Pathway #5: Next Generation production facilities, (pipelines over tank batteries, electrification, automation and remote decision support, comprehensive area development plans, super pads with long laterals

Pathway #6: greater deployment of multi-phase flow meters on well heads

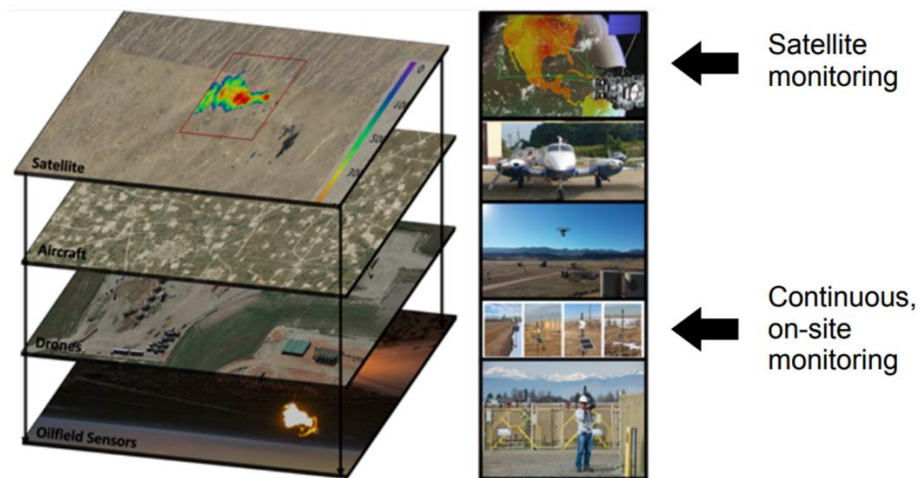
How you Measure Matters

Digital Canopy

Practical and affordable solutions for the identification, location, quantification, and remediation of methane leaks in oil and gas production equipment and facilities do exist today. However, most operators are still in the “experimental” stage of evaluating which technique works best under which specific conditions. There is an increasingly large amount of data being collected from oil and gas operations through the combination of satellite monitoring, drone or plane surveillance, and on-location sensors. Together, these provide the basic elements of a “digital canopy.”

Each of the techniques and technologies described has its opportunities and challenges. It is up to analysts to make the best of the data from each level. The next step is to build an integrated view, a “digital canopy”, that can bring in additional insights for policy makers, investors, regulators, oil and gas operators, midstream transportation and processing companies, as well as local communities. This is not a matter of which technology is the best. It is a matter of which technology solution brings about the greatest insight and value to a specific operations site. You can have too much data that confuses the picture so building the integrated model with all the relevant data is critical. Statistical and modeling techniques provide some useful tools in building digital twin models.

Digital Canopy



Top-down or Bottom-up/ Reconciliation or Adjustments versus Integration

Without an integrated view, the challenges of reconciliation between top-down and bottom-up measurements may become a stumbling block with new regulations. A discussion could end up with a debate on whether top-down or bottom-up reporting is better and not how the different approaches could be used together. Several research studies have shown that bottom-up methods consistently report lower emissions compared with top-down assessments, but a single explanation on the difference is hard to pinpoint. (Allen et al 2017; Alvarez et al 2016; Shen et al 2022) Industry leaders are turning to reconciliation as a next challenge to tackle for more accurate reporting. (Zavala-Araiza et al, 2015; Vaughn et al, 2018)) The new state of Colorado's rule making is headed for this questions, but is it a challenge or an opportunity?

Top-down studies are performed on a regional scale using various remote sensing techniques such as satellite and aircraft to measure ambient methane concentrations, calculate methane flux based on atmospheric, and meteorological conditions, and attribute the emission to different facilities, point sources and operational activities.

Bottom-up estimates rely on more local measurements, engineering calculations, manufacturers' data, and emissions factors for emissions sources and activities, compiled based on a representative sample basis to develop an aggregated account of emissions from a producing region or asset by operator.

There is no single best solution for emissions measurement approach in our opinion. Quite the opposite—there are many ways to track, measure, and report emissions. Within each, there are levels of uncertainty that need to be addressed to understand the true impact. With each producer taking on its own approach to methane emissions measurement, industry evaluators are looking for ways to take the data collected and reconcile it into standardized, more accurate reports. (EnergyNext 2022)

Methane emissions from the natural gas supply chain are a key factor in determining the greenhouse gas footprint of natural gas production and use. Recent estimates of these emissions have varied widely, because of the large population of sources, because of different measurement and estimation approaches, and because of extreme values of emission rates from individual sources that are much larger than population average values

of emission rates from sources in the same category (a ‘fat-tail’ distribution or super-emitters). Reconciling differences between ambient methane concentration measurements (top-down methods) and local direct measurement of emissions from individual sources (bottom-up methods) is critical to understanding methane emissions from the natural gas supply chain. An integrated combination of top-down and bottom-up approaches is recommended but it is also more difficult. (Allen, D. T. et al, 2014)

Estimating emissions quantities over time is complex – different approaches usually lead to different answers. Reconciling discrepancies among estimates is increasingly common as it can help improve understanding of the overall system. However, reconciliation is a new concept, and despite growing adoption, the term is used in different ways by different people, initiatives, and organizations. The simplest definition of reconciliation is to compare two different estimates and propose reasons for why they differ. (Fox, T., 2022) Another element of this debate is the reconciliation of “snap shot” monitoring (satellites) versus continuous monitoring versus lifecycle approaches to monitoring strategies and reporting requirements.

Measurement Wars: Dueling Data When Neighbors disagree

Air pollution from oil and gas operations in Colorado is on the wane, the industry says. But communities along the Front Range of Colorado — with their own air monitors — counter that they are finding repeated spikes of methane and other pollutants that are not reported. The Air Quality Control Commission adopted more regulations in 2020 to cut emissions from the preproduction phase (drilling and completions) of oil and gas operations. What the spikes and eddies in emissions means for public health and safety is still undetermined. But now stakeholders are arguing with data.

Monitoring for methane and other GHG emissions is not the same as direct measurement. There are too many potential emissions sources that direct measurement from all possible sources all the time is not feasible. Current monitoring techniques are influenced by many factors including wind direction and speed (as discussed in the section on Probability of Detection). So, the challenge of dueling data is inevitable.

As one example of this new occurrence of dueling data, in May, 2022, two industry groups — the Colorado Oil and Gas Association and API-Colorado — made a presentation to the Air Quality Control Commission with data showing that between 2013 and 2019 methane levels in the DJ Basin had decreased by 52% and at the monitor in Platteville, Colorado, operated by the state, ethane concentrations were down by 65%. The Platteville Atmospheric Observatory is about 5.5 miles southeast of Platteville, in Weld County, the most actively drilled county in the state. The industry groups’ findings were challenged by air quality officials from Longmont, Erie, Broomfield, and Boulder County, where some of the drilling closest to neighborhoods has taken place. The industry methane measurements were done by satellite for a large section of the Front Range, but the monitors located in communities. (COGA Fact Sheet, 2022 versus Boulder County rebuttal) Even with data, the two side could not agree.

Looking at the battling data, Commissioner Curtis Reuter said, “they don’t tell the same story. I guess the truth is somewhere in the middle.

These discussions are also taking place in other locations including the Crestone Peak Cosslet East permit in Arapahoe County and at the Pueblo Comanche Coal Power Plant. Just having data without a common context or framework is not going to bring different stakeholders together. This is another example of the situation where we are moving from the shallow end of this discussion to the deeper end. More education and context are required. Our section on can data build trust goes into this issue in more detail.

Impact of new technologies

Emissions detection technology has come a long way in the past few years. Now, with the recent advancements, operators, regulators and third parties can observe (identify) and locate emissions events and are getting closer

to being able to quantify methane emissions more accurately from the basin level, to the facility level and increasingly from the component (equipment) level in a matter of hours or days. This expectation is still a stretch for remote and widely distributed operations. Some detection options can monitor emissions on a continuous basis to address the intermittency of the emissions profile. (Johnson et al (2023) and Kemp and Ravikumar (2021))

In some cases, the economics support near real-time surveillance of operations from a remote decision support center and can predict and mitigate potential emissions. As these emissions detection technologies mature and new ones are developed, the industry believes they will be able to improve the accuracy of their emissions inventory reporting. New regulations are counting on this trend. This is the objective of measurement informed inventories.

In this section we briefly describe each of these key monitoring and measurement technologies:

Satellite remote sensing is one approach to answer some of the more regional or global questions around methane emissions. Satellites observe concentrations of methane from space by analyzing the way sunlight reflects off the Earth. As light passes through a cloud of the gas, its intensity is weakened on certain wavelengths. Methane absorbs light in the short-wave infrared portion of the electromagnetic spectrum.

Inferring methane emissions from satellite observations of methane columns involves different methods for area flux mappers and point source imagers. Area flux mappers are typically used to optimize 2-D distributions of emissions on regional or global scale by inverse methods. Point source imagers are used to infer individual point source rates by some form of mass balance analysis. (Jacob et al, 2022)

Here is the conclusion from research by the University of Wisconsin- Madison in their paper “Satellite Data Applications for Sustainable Energy Transition.”

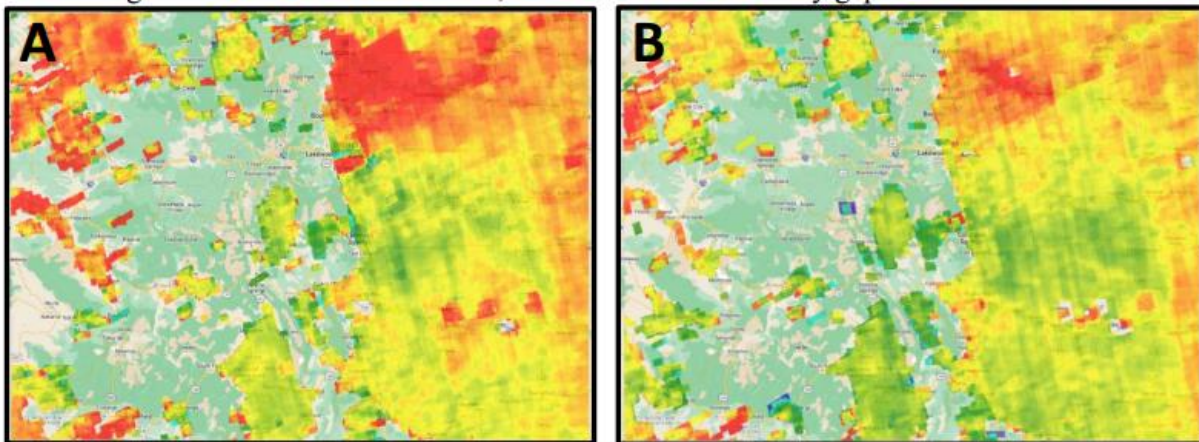
“Applications of satellite data are growing across a wide range of energy policy and planning problems. Recent developments are increasing the potential for satellite data to support energy and environmental decision-making, with new public and private satellites being launched, advances in data processing techniques, and efforts by government and private organizations to increase uptake in new user communities. With more complete spatial and temporal coverage, satellite data can fill gaps in traditional data sources. Often the value of space-based data is greatest through integration with existing data and decision tools. Many types of satellite data have been collected for years, enabling analysts to track changes in energy supply, demand and impacts over time and evaluate the effectiveness of policy interventions. While collecting satellite observations entails high fixed costs, the marginal costs are generally low, especially for datasets that are freely available to the public. Since data collection is remote, it also does not directly disturb local communities or the environment.” – Edwards, et al 2022

An orbiter called **Sentinel-5p** satellite with the **Tropospheric Monitoring Instrument (Tropomi)** with the instrument package, contains state-of-the-art sensors launched by the European Space Agency (ESA) in October, 2017. By April 2018, it had begun to produce data mapping the plumes of methane, carbon dioxide, nitrogen oxides, carbon monoxide and various aerosols over industrial facilities and cities as it passed over Europe, Asia, Africa, and South America. **Tropomi** measures solar backscatter between 380 and 2500 nm at 5 nm spectral resolution. Emission sectors with point sources plume characteristics detectable by satellites include oil & gas, wet manure management from animal feedlots, waste management from high-capacity landfills and coal mine seepage/venting. Other diffuse emissions, including enteric fermentation, dry manure management and wetlands, are not easily detectable with these types of imaging spectrometers.



Distribution of satellite data for use by decision makers and researchers is a continuing opportunity and challenge, especially as the number and complexity of data products grows. While researchers and high-end users may choose to navigate data distribution platforms, many stakeholders prefer GIS-enabled web interfaces developed for their application area. Four major limitations of satellite data include: timeliness, continuous data collection, consistent data across large geographic areas and availability of data at a very fine spatial resolution. (Dunn & Bazilian, 2022; Gauthier, 2021; Wang et al 2022)

Figure 1. Due to the interference, there are many gaps in the satellite data



record which produces unfinished maps that lead to distrust in total reporting. Methane concentration map of Colorado using the TROPOMI 5-P satellite. A) CO methane concentration for January 2022; B) CO methane concentration for February 2022.

The most obvious technical limitations in the use of satellite data for energy applications are primarily driven by insufficient spatial and temporal resolution. The resolution of different satellite monitoring tools varies with the satellite orbit and type of sensor package onboard. The **Landsat 8** satellite has a spatial resolution of 15-100 meters with a temporal sample rate of 16.0 days. The **VIIRS** satellite source has a spatial resolution of 375-750 meters with a temporal sample rate of 0.5 days. Satellites like **VIIRS** can help detect active flares especially

during nighttime, away from major urban areas, and then be used to calibrate the estimate for flared gas volumes.

There are several factors that can impact the accuracy and reliability of satellite emission monitoring:

1. **Cloud cover:** Satellites cannot see through clouds, so cloud cover can limit the ability of satellites to detect emissions accurately.
2. **Instrument calibration:** Accurate calibration of satellite instruments is critical for accurate measurements. Any errors in calibration can affect the accuracy of the data.
3. **Atmospheric conditions:** The concentration of methane in the atmosphere can vary based on several factors, including temperature and humidity. This can affect the accuracy of satellite measurements.
4. **Spatial resolution:** The spatial resolution of the satellite image can affect the ability to detect small sources of emissions, particularly if the emissions are dispersed over a large area.
5. **Interference:** Other sources of interference, such as sunlight or other sources of radiation, can interfere with satellite measurements, affecting their accuracy.
6. **Frequency of data collection:** The frequency with which satellite data is collected can affect the accuracy of the measurements. More frequent data collection can provide a more detailed picture of emissions, while less frequent data collection can miss changes in emissions over time.
7. **Data processing:** Accurate processing of satellite data is critical for obtaining accurate measurements. Any errors in data processing can affect the accuracy of the final results.

The **Landsat 8** image should be able to identify smaller flares compared to **VIIRS** images, although the longer satellite revisit time poses a challenge to identify less persistent flares. The Sentinel 5/ **Tropomi** satellite can get its resolution down to about three-square miles on Earth.

Other satellites will have different measurement specifications. The private Canadian satellite company, **GHGSat**'s data technology accurately identifies methane gas emission sources to individual facilities from unlit flares to open thief hatches, supporting leak detection and repair (LDAR) activities, production operations and environmental reporting. **GHGSat** developed the first sensor for small satellites that can detect methane (CH₄) emissions and locate individual sources of CH₄ from around 500km above the Earth's surface. **GHGSat** operates an existing constellation of five small satellites and a fleet of aircraft-based sensors that can perform facility-scale methane monitoring. Each satellite is equipped with an advanced methane sensor with a detection threshold of 100 kg-hr. and a spatial resolution of less than 30 meters.

Combining high spatial resolution polar orbiting measurements with high temporal resolution measurements from geostationary satellites will create unprecedented opportunities for energy and environmental policy. In addition to aircraft campaigns, point-source quantification will rapidly expand with emerging satellite missions

(**Carbon Mapper**: 2023 launch). Total basin flux estimations will also improve with wide-swath mapping missions (**MethaneSat**: 2023 launch).

The United Nations has announced a new satellite-based system to detect methane emissions to allow governments and businesses to respond. The **Methane Alert and Response System (MARS)**, launched at the 27th United Nations Climate Change Conference, is a data-to-action platform set up as part of the UN International Methane Emissions Observatory (IMEO) strategy to get policy-relevant data into the right hands for emissions mitigation. Developed in the framework of the Global Methane Pledge Energy Pathway – with initial funding from the European Commission, the US Government, Global Methane Hub, and the Bezos Earth Fund – MARS will allow UN to corroborate emissions reported by companies and characterize changes over time. MARS will be implemented with partners including the International Energy Agency, and the UN-hosted Climate and Clean Air Coalition.

MARS will be the first publicly available global system capable of transparently connecting methane detection to notification processes. It will use satellite data to identify major emission events, notify relevant stakeholders, and support and track mitigation progress. Beginning with very large point sources from the energy sector, MARS will integrate data from the rapidly expanding system of methane-detecting satellites to include lower-emitting area sources and more frequent detection. Data on coal, waste, livestock, and rice will be added gradually to MARS to support Global Methane Pledge implementation. (United National Environmental Programme, 2022)

Satellites are increasingly seen as a tool for identifying large greenhouse gas point sources for mitigation, but independent verification of satellite performance is needed for acceptance and use by policy makers and stakeholders. A study by Sherwin et. al. (2023) concluded that while the fraction of global methane emissions detectable by satellites remains unknown, they estimated that satellite networks could see 19-89% of total oil and natural gas emissions from a study in a high-emitting region. While that is quite a large range of uncertainty, satellites can be a useful data source in our study of global methane emissions.

Aerial Surveys: If Satellites do not meet your requirements, methane monitoring surveys can be flown by aircraft, helicopters, and drones. **Drones** provide many possibilities in a wide range of commercial and industrial applications from aerial photography, to surveys and inspection of structures. Custom drone designs with special sensors are becoming common in the oil and gas industry, where they are helping to monitor their assets remotely, safely and cheaply.

Other than the usual photography, the drone technologies can gather additional information such as gas leaks and thermal images. Pairing the drones with the appropriate sensors enables companies to gather comprehensive data from the remote locations at a fraction of the costs of traditional methods. Drones with laser-based sensors can fly over a field for 40 minutes on a single charge and beam back data to a central collection hub. Additionally, this type of sensor can determine the extent of the leak, whereas the infrared camera can only detect its presence, not its severity. The drone is also loaded with custom software that allows it to plan its own flight and analyze the data it gathers. (Churchill, et. al., 2022)

The methane detection drones detect the leaks using light reflection and absorption sensors. The sensors emit eye-safe lasers, which are reflected in specific ways upon hitting certain matter such as gases. Analyzing the reflected beam enables the drones to pinpoint leaks. Generally, the sensors can identify the methane spectral signature based on the reflected light and determine the presence or absence of the gas. The Colorado Oil and Gas Conservation Commission began piloting their own drone program in 2018 to augment field inspectors. Several other oil and gas operators (like ConocoPhillips in New Mexico) also have their own drone fleets.

Here are a few examples (far from comprehensive) of aerial methane measurement companies and their technologies and techniques:

- **Bridger Photonics** -- Aerial light detection and ranging sensor (LiDAR) to pinpoint and measure leaks. : Bridger Photonics was founded in 2014 by several laser physicists (Peter Roos as CEO) with ARPA-E funding to develop their idea of an active gas-mapping LiDAR (laser radar) with both

topographic and atmospheric LiDAR components combined with aerial photography to create 3D models of: physical infrastructure, gas plumes in air column, wind speed with weather tower and mass emissions rate, can be flown on either planes or helicopters

- **Scientific Aviation** – Airplanes equipped with sensors, coupled with weather and atmospheric information to measure methane emissions.
- **Kairos Aerospace** – Kairos Aerospace **LeakSurveyor** is an airplane mounted methane imaging system that combines an infrared imaging spectrometer, global positioning system (GPS) and inertial monitoring unit and optical camera to detect methane plumes.
- **NASA JPL** – the next generation airborne visible/infrared imaging spectrometer (**AVIRIS-NG**) is an improvement on the original AVIRIS instrument developed by NASA’s Jet Propulsion Laboratory (JPL). The AVIRIS-NG instrument is a push-broom imaging spectrometer with approximately 5nm spectral resolution over visible and near-infrared spectra (380 to 2510nm).
- **Leak Surveys Inc.** – Helicopter-mounted, gas imaging surveys.
- **DroneDeploy** – Headquartered in San Francisco, California DroneDeploy is the easy and fast solution to build aerial maps and models. DroneDeploy has two major components: 1) Flight Automation and Data Capture. Customers flying DJI drones can capture imagery using the DroneDeploy mobile app. This will simplify flight planning as well as ensure appropriate coverage and overlap of imagery. 2) Data Processing and Analysis. Process data from DroneDeploy flight, or use Map Engine to process imagery from any drone.
- **SeekOps** – Founded in 2017, based out of Austin, Texas, SeekOps provides low-cost, accurate, and efficient emissions inspection services to oil and gas companies in the United States and global markets. Leveraging expertise in small unmanned aerial systems (UAS) coupled with proprietary methane sensing technology, SeekOps provides industry services and sensors for leak detection, localization, and quantification. SeekOps provides emissions inspection services to the oil and gas industry, including several supermajors and various gas utility companies both domestically and internationally.
- **BakerHughes Avitas**– Emissions management tech will become more automated, shifting from widget-driven to data and analytics-driven via the increasing application of AI and machine learning. Combining AI with direct measurements and process-based predicted emissions that use physics-based models will lead to more intelligent models of emissions performance and smarter abatement planning.

Continuous Measurement System – The Continuous Measurement system is a network of fixed sensors designed to detect, locate, and quantify methane emissions in real-time. The technology consists of three components: 1) an Industrial Internet of Things (IIoT) device that measures gas concentration and environmental data and transmits it to the cloud, 2) a cloud-based platform that records and analyzes data received by the IIoT devices, and 3) a web-based user dashboard that aggregates critical insights generated by the analytics platform and identifies the remedial actions that need to take place by maintenance and repair teams. (Benko, et. al., 2023)

There are three broad classes of **Continuous Emission Monitoring systems (CEMS)**: solutions that create actionable information using 1) a sensor network that provides point-in-space concentration observations at fixed time intervals; 2) scanning lasers to measure long, integrated open-path concentrations; and 3) cameras to create 2D images of concentration enhancements. (Daniels, et. al. 2022)

Monitoring for fugitive emissions has historically been performed using handheld technologies such as Optical Gas Imaging (OGI) cameras as part of Leak Detection and Repair (LDAR) programs (direct measurement). Handheld approaches have been part of regulatory rule making for years because they have relative low detection thresholds and lead to actionable results. However, just like all “snapshot” approaches, a growing body of research suggest that handheld approaches often miss the largest and most important sources (super-emitters), either because they are inaccessible or due to the periodic nature of many methane sources that may not coincide with OGI survey timing.

Direct measurement is deemed the most accurate method for quantifying annual methane emissions. Direct measurements also contribute to greater certainty on emissions levels and economic costs and benefits, allows for decisions based on fact, and accurate field data. Identification techniques include: Optical leak imaging (IR camera), Laser leak detector (RMLD), Soap bubble screening, Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs) and Acoustic Leak Detection. Quantification techniques include: Turbine meters, Thermal Dispersion Flow Meters, Calibrated vent bag, Vane anemometer, Hotwire anemometer and High-volume sampler. On-site solutions that can continuously monitor methane and Volatile Organic Compounds (VOCs) at the wellsite are starting to emerge. Unlike intermittent methods, the unit detects when and where an emissions leak is occurring in real-time, enabling an operator to rapidly mobilize a team to the site and minimize fugitive emissions. (Ravikumar et al, 2017; Ravikumar et al 2018)

Some regulatory agencies (like Colorado and Alberta) have begun to allow continuous monitoring to replace or complement OGI at the discretion of the regulator. To be approved, proponents must demonstrate that emissions mitigation under the proposed program is equal to or greater than the standard in the current regulation. But establishing equivalency is complex. (Fox, et al 2019; Fox et al 2021)

It is important to note the trade-off between detection limits and time to detect of these different methods. Continuous measurement techniques generally have higher detection limits than OGI camera and therefore might miss smaller leaks that OGI cameras would identify. However, due to the heavy tailed nature of most empirical leak-size distributions, larger leaks have greater consequences. Finding large leaks sooner yields greater mitigation (time to fix and repair equipment and stop leaks) than finding leaks of any size less frequently.

Characterizing methane emissions on oil and gas facilities through continuous emissions monitoring systems often relies on a forward model to describe the atmospheric transport of methane. In other words, you need to measure the wind. This makes the challenge of identification, localization, and quantification a much more difficult challenge than you might think at first blush. Researchers are using local weather measurement and sophisticated dispersion models to solve these problems. (Jia et al, 2023)

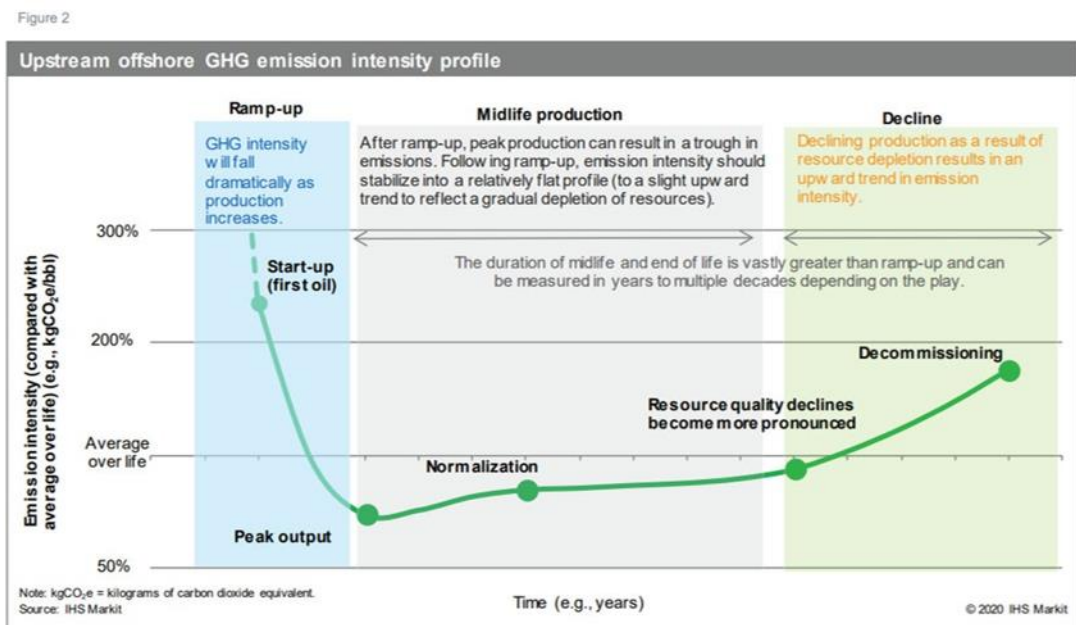
To date, most CEMS systems are focused on the commercial market of providing services to operators, not for verification of public reporting. While this is a growing activity in helping operators identify and locate leaks for more responsive LDAR and maintenance activity and sometime for verification of certified natural gas commercial contracts, the state and general public do not get access to these measurements and reports. A new business model would have to be developed for these studies to be part of an operator's obligation to report annual emissions to a state regulatory agency.

Here are a few examples (not comprehensive) of continuous emissions monitoring system contractors and their technologies and techniques:

- **Project Canary** - Project Canary® is an environmental data and software company that collects, analyzes, quantifies, and visualizes asset-level environmental risk assessments and emission profiles. As a measurement, reporting, and verification (MRV) solution, the Canary SENSE Platform™ integrates a networked sensor canopy, including 3rd party sensor data and assessment scores, to provide independently verifiable climate attribute data for upstream, midstream, and CCS (carbon capture and sequestration) projects.
- **LongPath** - LongPath Technologies uses patented, Nobel Prize-winning, long-range laser networks to provide the lowest cost detection and quantification of specific emissions sources across large areas.
- **Qube** - Qube monitors for harmful gas leaks around the clock, without the need for human operators, pushing out alerts when detection events occur. Their physics-guided algorithms infer leak quantity, location, and classification, helping operators determine which leaks to prioritize for repair.

When You Measure Matters

There are at least two major factors influencing when you should measure: 1) the Lifecycle of production activities (pre-production phase) and the intermittency of venting and fugitive emissions. In each case “snapshot” surveys may or may not catch the emissions event and if it does you are left with the problem of estimating the duration of the event to calculate the total emissions lost.



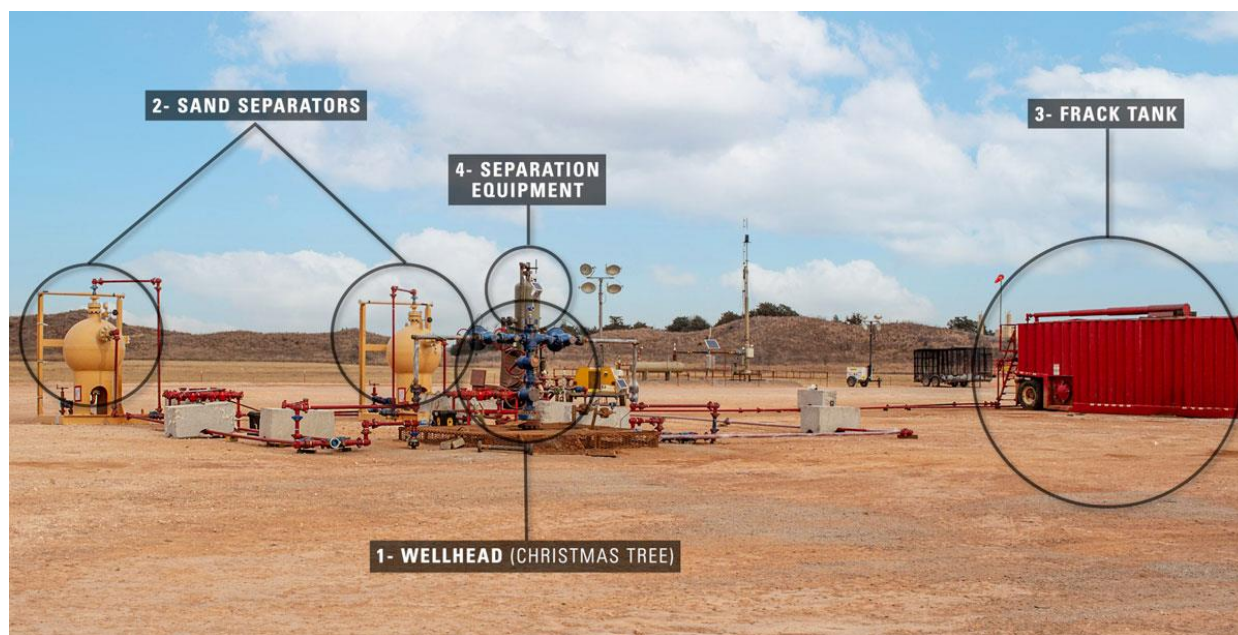
The slide from IHS Market demonstrates the emissions from the “ramp-up” or pre-production phase can be significantly higher than emissions during the production phase. Comparison of results between the two period are not particularly relevant and can lead to the dueling data challenge mentioned previously. Pre-production activities relate to the drilling of the well and the completion stage. In many cases the infrastructure (pipelines, tanks, etc.) to capture natural gas is not in place. In the “flow-back” phase after the well has been hydraulically fractured is a time when the water and sand used in the fracturing returns to the surface cleaning out the well for production and carries natural gas and dissolved hydrocarbons and is usually discharged to a retaining pond or captured in frac tanks.

There are more efficient and modular techniques to handle emissions in the pre-production phase than flaring such as incinerators and enclosed combustors. An enclosed combustor is a newer iteration of the incinerator. The combustion device is completely enclosed except for the combustion air intake and the exhaust discharge. It operates like an incinerator with more restriction to allow it to be able to operate in a reduced spacing capacity. One example of a company that provides this technology as a service is Questor Technology Inc. <https://www.questortech.com/> .

What is flow-back?

After a well has been drilled, the casing cemented, the shale fractured, the pad laid, and the piping and production equipment installed, the flowback phase begins. Flowback typically lasts between 30 and 120 days. The fluid produced during this phase is a mixture of crude oil, natural gas, water, and sand. A producer’s goal during this period is to manage the sandy flowback fluid and keep the well open and running so it can normalize and more freely flow oil and gas.

The fluid first flows up the well bore and through the wellhead, which is often referred to as the “Christmas tree.” From there it moves to sand separators. Sand separators spin the production fluid, which creates centrifugal force. This is where the bulk of the sand is processed out of the fluid. It is then piped to on-site frac tanks, which trucks will retrieve throughout the process. Producers then flow the fluid through a variety of separators. These include two- and three-phase separators, free-water knockouts, and heater treaters. These vessels separate the fluid into its three primary elements—gas, oil, and water. What sand remains sinks to the bottom of the vessels and gets processed out with the water. <https://kimray.com/training/flowback-quick-guide#>



Frequency of Sampling and Probability of Detection: How often do methane measurements need to be made?

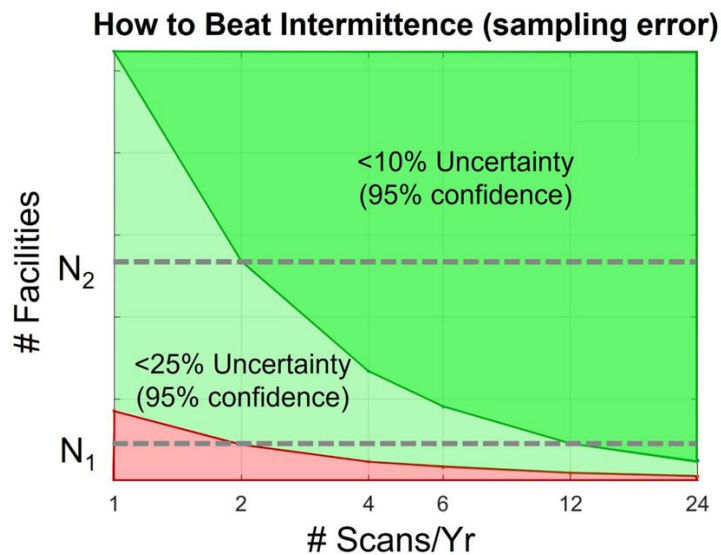
A good definition of the probability of detection comes from Conrad, et al (2022). “For a specified remote detection technology, the probability of detection (POD) function represents the likelihood of successfully detecting an emitter at some source rate for a given set of conditions during a single measurement observation. Although different technologies may be affected by additional parameters, in general, detectability of a given source (at rate Q) depends on the wind field that drives plume dispersion the spatial resolution of the measurement, and the effective signal-to-noise ratio (SNR) of the measurement system.”

EPA modeling indicates that (presumably for perfect detection sensitivity and spatial coverage), quarterly scans would catch 80% and monthly would catch 90% of a single facility’s emissions. This might be a reasonable starting point, but measurements by Carbon Mapper of the fat tail portion of the distribution indicate that intermittent emissions need to be considered to get the full picture.

For national- or basin-scale inventories (1000’s of facilities), it is possible that a single scan might be sufficient to overcome the many uncertainties that exist. This is because there are so many intermittent emissions that an emission disappearing on one site is reliably replaced by another appearing on a different site. In several studies Carbon Mapper found larger emissions to be less persistent (they do not last long, so have less impact on the annualized inventory). This seems natural considering the large emissions often trigger SCADA alerts and are fixed quickly.

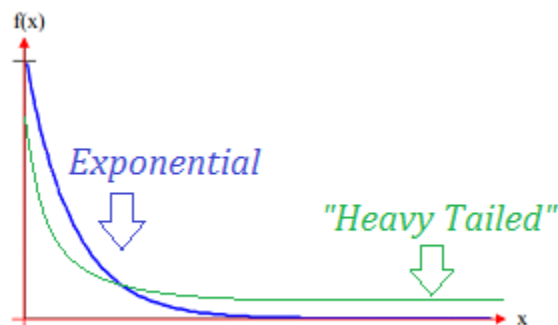
At the other extreme, for an operator with just a single site, the site may need to be scanned monthly or more frequently to achieve the desired result. But what about in between those two extremes? How often does an operator with 20 facilities need to scan to beat intermittency? This only takes care of random errors like intermittency. Systematic errors due to, e.g., measurement bias, inadequate detection sensitivity, incomplete spatial coverage, seasonality, and diurnal trends also must be included. (Conrad et al, 2023)

Peter Roos from Bridger Photonics has written extensively on the challenge of overcoming intermittency. To quote one of his many blog posts: “First, choose an acceptable level of uncertainty due to intermittency. With this choice (i.e., <10% uncertainty with very high confidence), the plot identifies all the combinations of # of facilities and # of scans/yr. that will achieve that level of uncertainty or better (the region up and to the right of the 10% curve). The larger the number of sites, the less frequently those sites must be scanned to get the right answer. For small site number, the similarity of sites (i.e. ergodicity) also needs to be evaluated properly.” The following figure comes from their work on sampling error. (Roos, LinkedIn post)



Studies have shown that unplanned fugitive emissions can follow a distribution where significant emissions events (by volume of emissions) do not happen very often but when they do can contribute a large percentage of the total annual emissions (heavy tail. This makes “snapshot” surveys even more problematic. So, what is a heavy tail distribution? (Brandt et al, 2016; Lavoie et al 2017))

Heavy tail distribution



A heavy tailed distribution has a tail that is heavier than an exponential distribution. In other words, a distribution that is heavy tailed goes to zero slower than one with exponential tails; there will be more bulk under the curve of the PDF. Heavy tailed distributions tend to have many outliers with very high values. The heavier the tail, the larger the probability that you will get one or more disproportionate values in a sample. <https://www.statisticshowto.com/heavy-tailed-distribution/>

What do we mean by incentives for the industry to reduce emissions?

We all know what penalties mean. They could come in the form of a fine or even a denial for a permit to drill or operate. But often the term incentive is used by environmental groups in this context as a reduction in penalties (carbon offset can go against taxes, or verification proves an operator is playing by the rules) rather than an economic benefit for reducing emissions. In general, incentives are anything that persuade a person to alter their behavior in a specific direction. It is emphasized that incentives matter by the basic laws of economics and the laws of behavior, which state that higher incentives amount to greater levels of effort and therefore, higher levels of performance. This is a question for the state and federal regulators. What is the best way to incent the oil and gas industry to lower their methane emissions, is it through a penalty, or a carbon tax; the absence of a penalty; a market price signal; a carbon credit; or a mixture of some or all these financial and regulatory tools?

“The importance of methane emissions reductions is underscored by the US government’s social cost of methane estimate of \$31 / mcf, about 10 times the market price of natural gas. Because the price of natural gas is relatively low, producers have little financial incentive to reduce emissions by capturing and selling the methane they release. Pricing methane emissions is a straightforward way to help oil and gas producers prioritize methane emissions reductions. Pricing could occur through state or federal emissions fees, or “responsible gas markets” in which certified low-methane producers receive a market premium.” (Agerton and Gilbert, 2021)

Certified natural gas (a market signal, a carrot instead of a stick)

More Natural Gas producers are turning to third-party audits to differentiate their production streams as certified natural gas or sometimes called RSG (Responsibly Sourced Gas) to comply with the investment community’s ESG (environment, social, and corporate governance) requirements. In a study issued in 2021, the global research and business consultancy Wood Mackenzie referred to RSG certification as a “nascent” industry (audit companies tend to be innovation-driven data analytic startups) and noted that “certification processes exist (currently) only for upstream assets and there is no universal or industry standard.”

“Certification is based on standards such as air emissions, water stewardship, land use, and community impacts,” Wood Mackenzie reported. “RSG differs from normally produced natural gas in that producers take extra steps to reduce their carbon footprint, mitigate emissions, and minimize environmental and social impacts.” Wood Mackenzie expects RSG to play a major role on the path to decarbonization for North American gas markets. A critical factor in making this happen is being able to track each RSG molecule from the ground to delivery. (<https://www.validere.com/webinar/global-energy-summit-rsg>)

According to Project Canary, Responsibly Sourced Gas (RSG) is natural gas that has undergone independent 3rd party assessment that molecules were produced under specified environmental best practices. Calculating methane intensity, water usage, and other climate factors helps producers meet standards set by gas buyers, academics, and other stakeholders. (Project Canary, 2023)

The first purchase of certified natural gas was in 2018, when Southwestern Energy Co. publicly announced that it struck a deal to sell RSG gas to utility New Jersey Natural Gas (NJNG) from a group of wells in West Virginia for a premium to local Appalachian index prices. With a growing list of utilities, interstate pipelines and

gathering/processing midstream firms including RSG natural gas purchases, it is estimated that more than 25% of Today's US Natural Gas Volumes are Certified Low Methane Intensity (<0.2% production leak rate). (Project Canary, 2023)



Certified natural gas monitoring might only collect empirical data—which is a start—but it is largely at pad level, ignoring the bigger picture that can be assessed only from space. That bigger picture is what the EPA will turn to when it begins to levy its methane tax in 2024 and it is why the industry is starting to look “up” as well.

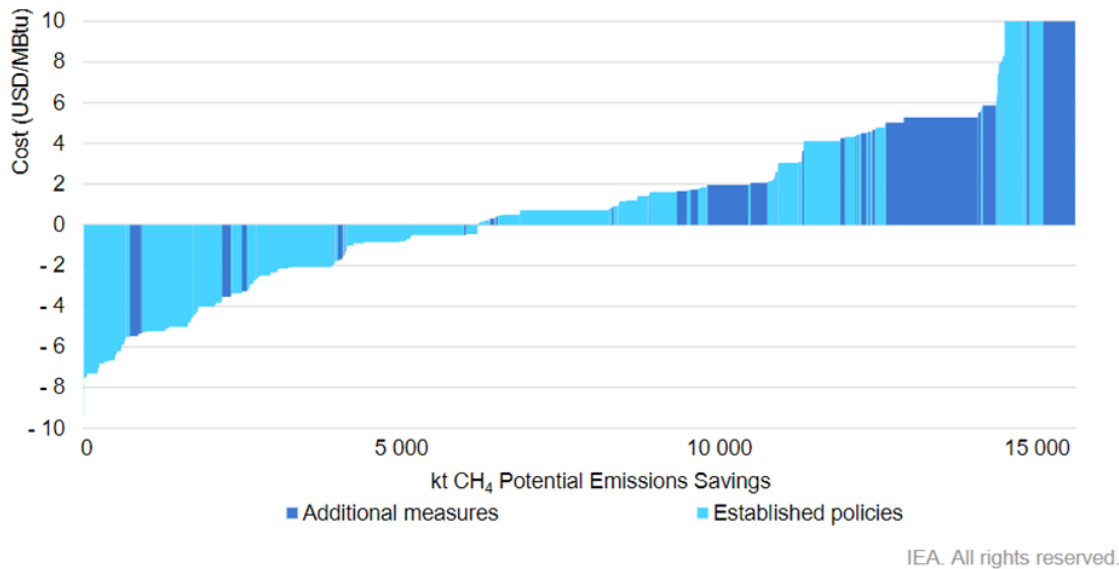
Methane Abatement

In a speech at the COP27 meeting in Egypt, President Biden said “*a good environmental policy is a good economic policy.*” The leading oil and gas operators seem to be using a playbook that switches those two priorities, “*a good economic policy is a good environmental policy.*” Natural Gas (methane) is the primary product of natural gas producers and an important secondary product for crude oil production with associated natural gas. It is bad economic and operational practice to emit (essentially waste) your product into the atmosphere when there are practical ways to minimize those emissions.

The goal is simple – keep methane in the pipe. To achieve this many of the leading oil and gas producers are using detection and direct measurement technologies, as well as proven operational practices, to improve their understanding of industry emissions. Efforts to reduce methane emissions mean more natural gas is available to heat homes, generate power and meet the many other needs of modern society. But not everyone is convinced the industry is that dedicated to that simple goal.

Methane mitigation must pay for itself (but the good news is that it often does). Studies by the IEA (2022, see figure below) and others have attempted to rank list different methane abatement methods and assign a potential emissions savings to each. Here is one example of such a study. The good news is that many methods pay for themselves just from the capture of lost natural gas production. Other methods have a cost that varies with the commodity price swings. Other emissions will require a redesign of operations to achieve emissions targets.

Figure 2.2 Methane abatement cost curve for policies in committed countries, 2020



With all the recent attention to new rule making, like the Colorado state verification of methane emissions, the oil and gas industry is asking federal and state regulatory agencies a serious question. Will the final rules and regulations disincentivize adoption of advanced tech compared to traditional OGI methods? Adoption and application of newer technology will likely find more emissions sources as the complete picture is unveiled. But will that attract larger fines and penalties? Will the industry be punished for moving in the right direction with more measurements? The shared goal should be the reduction of methane emissions. With that result in mind, Bridger Photonics have suggested two revisions to proposed EPA methane rules based on the fundamental objective of eliminating emissions and not just adding more penalties to the new regulatory frameworks might be justified, we agree:

- 1. Provide an opportunity for operators to mitigate detected compliance issues instead of immediately classifying them as violations. With more comprehensive spatial and temporal coverage, advanced tech will detect many more emission sources than OGI that represent compliance issues (e.g., malfunctioning control devices, cover, and closed vent system failure...). This is a good thing, but penalizing operators with an immediate violation/fine creates a strong disincentive inhibiting adoption of advanced tech that will reveal these problems. Allow the operators to fix the problem first as a compliance pathway.*
- 2. Capitalize on the enhanced capabilities of advanced tech instead of requiring a “blanket” full-site follow-up OGI survey. Every detection by advanced tech triggers a *full-site* follow-up OGI survey, even if the tech identifies the emission source, even if the emission source is not required to be monitored by standard OGI, and even if the advanced tech shows the emission source no longer exists (intermittent). This penalizes the detection of emission sources and favors standard OGI. To remove this disincentive, do not require OGI follow up if the emission source can be conclusively identified by the advanced tech or is intermittent. And when it cannot be identified, only require OGI follow up within the localization uncertainty of the advanced tech. (Peter Roos, Bridger Photonics)*

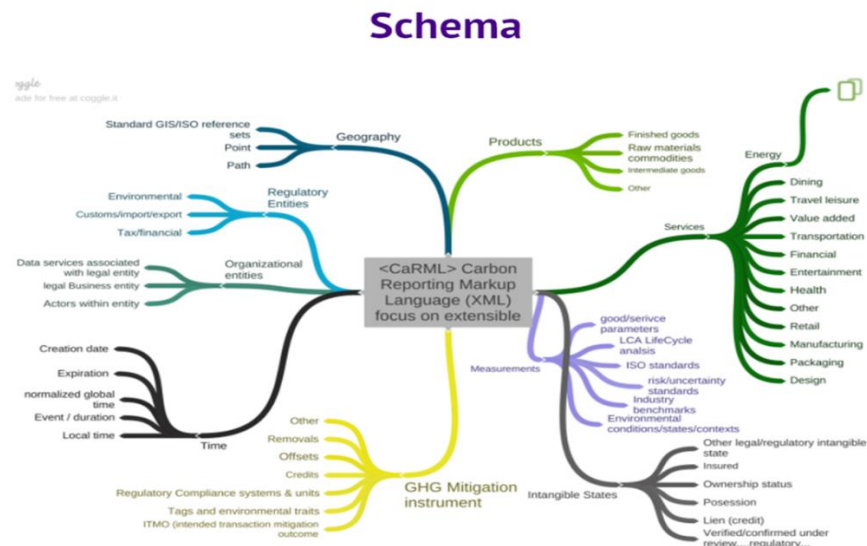
How You Report and Display Measurements Matters

Can Data become the common language for our public discourse on methane emissions? Can reporting requirements be simplified? Can the process to publish data for public viewing be expanded? Communication to a very diverse audience of complex technology and statistical methods will not be easy. Will the public understand the new emissions targets and the limitations of new measurement technologies and how they related to state net-zero road map or EPA ozone limit reductions?

The goal of the standards programs like the GTI sponsored Veritas program (which CDPHE is working with) is to develop technical protocols for measurement, audit, and assurance and provide a widely accepted methodology to incorporate field-informed methane quantification into emissions inventories. The protocols are being developed with technical experts, leading academics, environmental non-governmental organizations, and industry peers. Successful adoption of these types of protocols will help create consistent and transparent methodologies for companies to calculate and report methane emissions. But will these standards gain wide acceptance?

Reporting of methane emissions may seem like a simple task but as this data schema proposed by a new standards project by CarbonML demonstrates the complexity of the reporting task. The Carbon-ML project is developing an extensible open-source ecosystem for providing declarations of measurements for embodied carbon in any product or service. <https://carbon-ml.org/about-us-2>

Methane Emissions as a data object (CarbonML)



Colorado's new emissions inventory database (Oil and Natural Gas Annual Environment Inventory Reporting or ONGAEIR)

*“An **emissions inventory** accounts for every source of greenhouse gas emissions from within a company’s portfolio. At its core, a simple emissions inventory multiplies “emissions factors” (emissions per source) and “activity factors” (how many sources there are), to arrive at an estimate of a company total. This may include combusted, vented, and fugitive emissions. There are many ways that this can be improved and made more accurate, such as using company-specific emissions factors, rather than industry averages, using data from direct measurement, or considering specific operating parameters for the equipment in question. This provides companies a more accurate view into their past and current emissions and helps identify opportunities to make long-term improvements.”* (Strange, 2023)

The Colorado Department of Public Health and Environment created the Climate Change Program in December 2019 to lead an ambitious effort to reduce greenhouse gas emissions. The program is responsible for conducting the statewide Greenhouse Gas Inventory, developing regulations to reduce greenhouse gas emissions, and gathering input from stakeholders and communities to shape an equitable and effective response to climate change in Colorado.

Prior to 2020, industry operators submitted their annual emissions inventory report through the APEND process which was sent by email to the APCD with a spreadsheet attachment. It required a large manual effort to consolidate these reports into a combined report to the AQCC. The 2020 annual report was published in mid-2021. With all the changes required in the Climate Change Program and the new ONGAEIR data base the 2021 the raw data has been released but the final report has not been completed as of March 2023. Why is it taking so long? Complexity, resources and new technology are the answer.

A new process was adopted for the 2021 emissions inventory when the new ONGAEIR data base was rolled out. The Unique operator identifier is consistent across the APCD including the air quality permit but is unique to the APCD. The operator identifier is different for the COGCC's permit data base but the two can be linked through the common geographic location data attribute. All this reporting is unique to the state agencies and operators are required to also report emissions to the EPA GHGRP for large source emissions. The requirements for the state of Colorado are more detailed and are required from all operators. But the EPA requirements are also changing. Green House gas emissions from snap shot surveys of orphan wells are not yet included in the ONGAEIR database.

ONGAEIR is a customized database that aligns with state regulator requirements. Commercial alternative options exist like: Xpansiv built for carbon offset trading or commercial software HSE solutions like Intalex Environment Management software (<https://www.intalex.com/>). The new Highwood Emissions Management Emissions Management Toolkit (<https://highwoodemissions.com/software/>) has four modules: Emissions Insights, Reduction Pathways, LDAR Simulator and Measurement and Reconciliation (in development). Several operators report that the state's comprehensive database modernization project is still not completed and is difficult to upload the required information. This is still a work in progress and still too reliant on spreadsheet data manipulation!

The web portal and submission form for submitting annual GHG reports as required under Air Quality Control Commission (AQCC) Regulation No. 22, Part A, can be accessed from a state webpage link (<https://oitco.hylandcloud.com/CDPHEGHGExternalAccess/Account/Login.aspx>). The web portal and submission form must be used by entities subject to Colorado's GHG reporting requirements. A registered user account is required to access the submission form.

For GHG reporters subject to AQCC Regulation 22, Part A, the Air Pollution Control Division requires that GHG emissions be reported to the State of Colorado using the XML file generated for the facility or entity from the U.S. Environmental Protection Agency's (EPA) Electronic Greenhouse Gas Reporting Tool (e-GGRT), which may be accessed at <https://ghgreporting.epa.gov>. GHG reporters subject to Colorado's GHG reporting requirements but not subject to EPA's GHG reporting requirements can still use e-GGRT to generate an XML file for reporting to the State of Colorado without reporting their GHG emissions to EPA.

Here is a short segment from the production FAQ from the APCD about reporting requirements. *“The Colorado Department of Public Health and Environment, Air Pollution Control Division (Division) intends for the following instruction document to guide the completion of Form 22-402 for the reporting of emissions associated with oil and gas operations in Colorado. The following document defines the reporting requirements for each activity category listed in Colorado Regulation No. 7, Part D, Sections II.G, and V.C.*

The Division intends for this document to address the production equipment spreadsheet, form 22-402. For instructions about “UIC,” “pre-production,” and “midstream & pipeline” annual emission inventory submissions, refer to the “UIC” spreadsheet (form 22-403), “pre-production” spreadsheet (form 22-401) or the “midstream & pipeline” spreadsheet (form 22-400) and associated instruction documents.

The Division has been through three (3) iterations of spreadsheets. In 2020, all reporters submitted the spreadsheets through the Greenhouse Gas web-based form in OnBase. In 2021, the Division developed a database to house all reporter submissions. A new web-based form in OnBase was developed to accept all spreadsheets: Oil and Natural Gas Annual Emission Inventory Report. For the reporting year 2022, the Division has updated the ONGAEIR form to include requirements passed by the AQCC in December 2021. Additionally, the form has been updated to expand and improve data reporting. The Division is developing the greenhouse gas intensity verification rule-making, and additional data points required for statistically analyzing emissions from oil gas operations have been included. The Division will revise the form again after finalizing the greenhouse gas intensity verification rule.

Regulation 7, Section V is defined by the following applicability.

Regulation 7, Section V.A.1:

On or before June 30th, 2021 (and on June 30th each year thereafter), the owner or operator of oil and natural gas operations and equipment at or upstream of a natural gas processing plant in Colorado must submit a single annual report that includes actual and specified information in the Division-approved format.

Regulation 7, Section V.A.2:

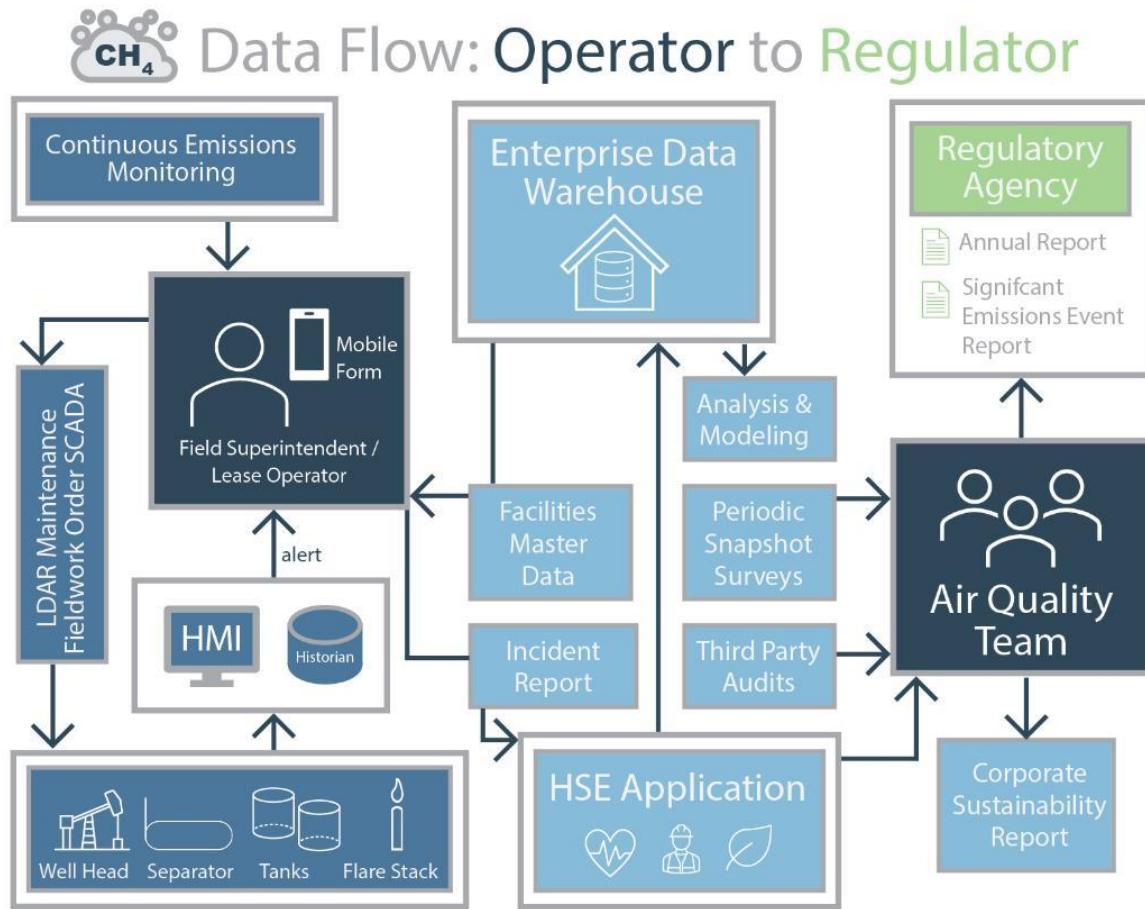
On or before June 30th, 2022 (and on June 30th each year thereafter), the owner or operator of class II disposal well facilities that are not subject to reporting under Section IV must submit a single annual report that includes actual emissions and specified information in the Division-approved format. For continued improvement of public health and environment in the State, the purpose of Colorado’s Regulation 7 is to establish an inventory of emissions from all equipment listed in Regulation 7, Part D, Section V.C. or Section II.G regardless of whether the equipment is permitted or not, is below de minimis emissions or not, and whether or not the device has an APEN.

Reporters should carefully review reporting applicability. Only the owner or operator of oil and natural gas operations and equipment at or upstream of a natural gas processing plant in Colorado must submit an annual report under this section. Businesses co-located with oil and natural gas operations but not included in extracting, processing, or bringing petroleum products to market should consult the division before reporting emissions to ONGAEIR.” <https://cdphe.colorado.gov/ongaeir>

The following diagrams depict an example of the data flow from:

- 1) the operator’s perspective
- 2) the state regulatory agency perspective
- 3) an ideal state view that all stakeholders should be targeting from our view.

The Operator's perspective



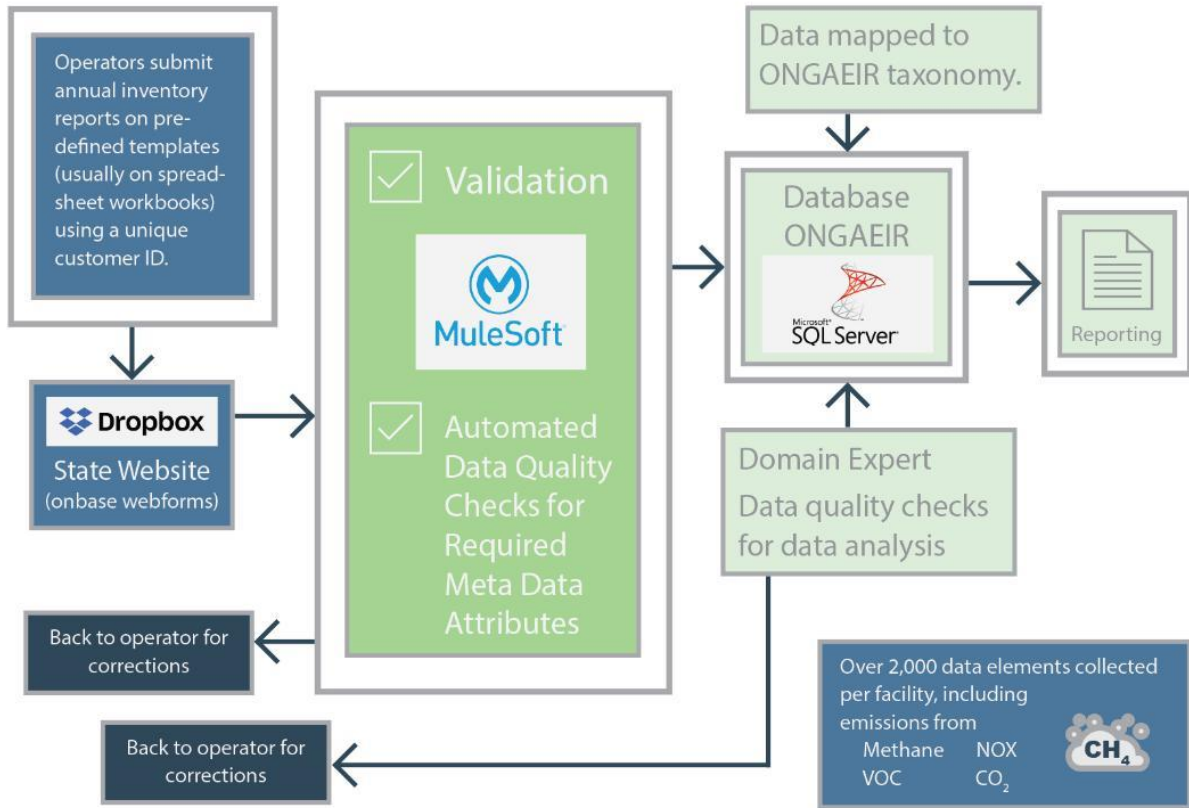
There is no single, standard way that operators today monitor and measure their greenhouse gas emissions. A lot depends on the complexity of the production facility, infrastructure, and maturity (age) of the facility. The preceding diagram brings together several ideas of site measurement including a process control (SCADA) system, periodic LDAR surveys, continuous emissions monitoring systems, mobile alerts and webforms in the field that alert operations and maintenance staff and field superintendent when an incident occurs.

This data is connected to corporate HSE (health safety and environment) applications, where periodic “snapshot” surveys (aerial or satellite) data can be included, and possibly even input to an enterprise data warehouse for additional analysis and modeling. At the end of the process the operator’s air quality and permitting team are responsible for submitting the required information to the state and federal regulators and to compile the operator’s annual sustainability report. Not all operators have all these elements but this diagram give you a sense of all the people and systems that can be involved.

The state regulator's perspective

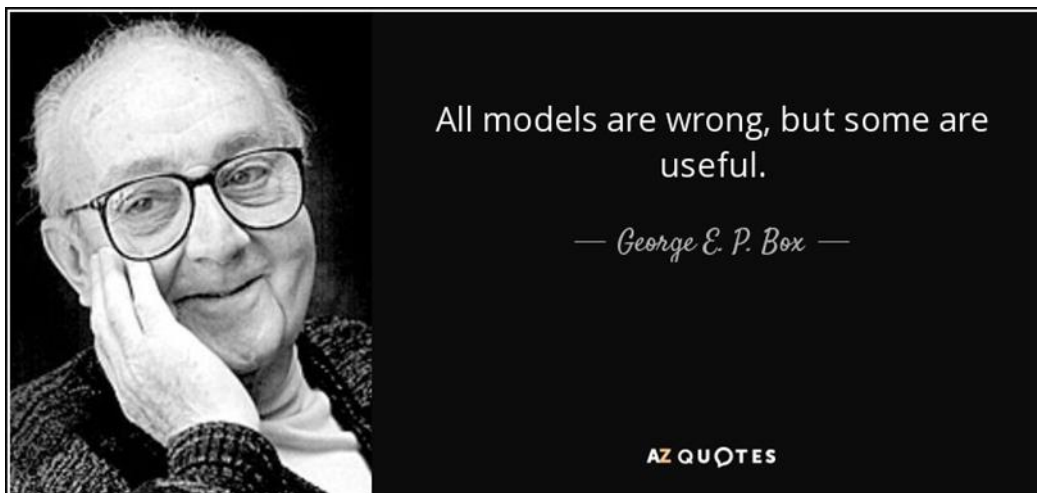
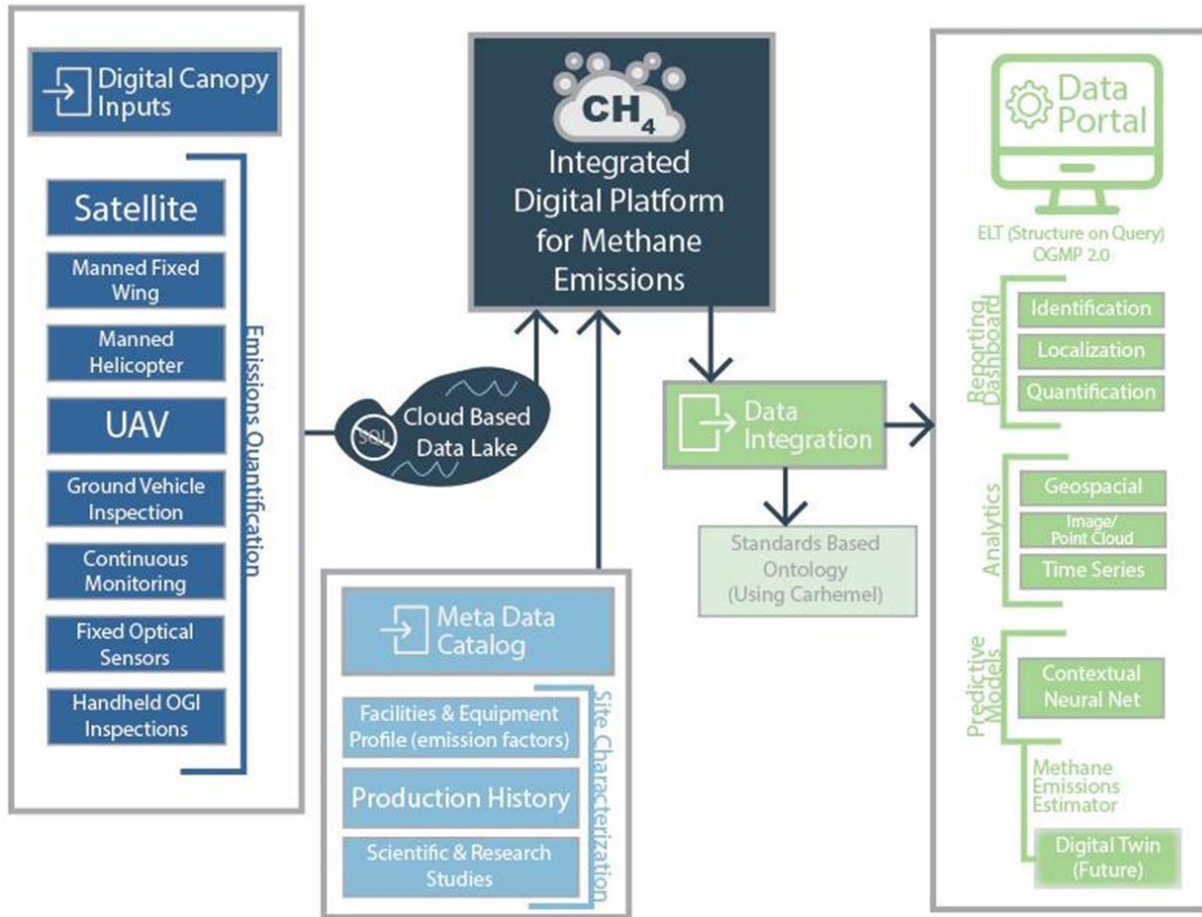
The Air Pollution Control Division is redesigning the way emissions data will be input from oil and gas operators and how that data will be handled inside the Division. This includes the new ONGAEIR database. The following diagram represents the data flow that is now being installed by the division staff.

CH₄ Data Flow: Input to State Regulator



Ideal Future State

This is a simple cartoon we came up with for a very complex conceptual data and systems architecture for integration of data from each of the digital canopy levels. To our knowledge no operator is at this stage but it is an ideal to aim for. The main objective here is to integrated the data from all relevant digital canopy layers instead of just capturing each layer and going through a reconciliation step.



Forecasting emissions

With all the data that is becoming available from multiple sources from diverse levels of the digital canopy, you might think that we are getting close to the ideal of direct measurement of methane emissions. But the truth is we are just becoming more dependent on computer models. Given the uncertainties described in this paper

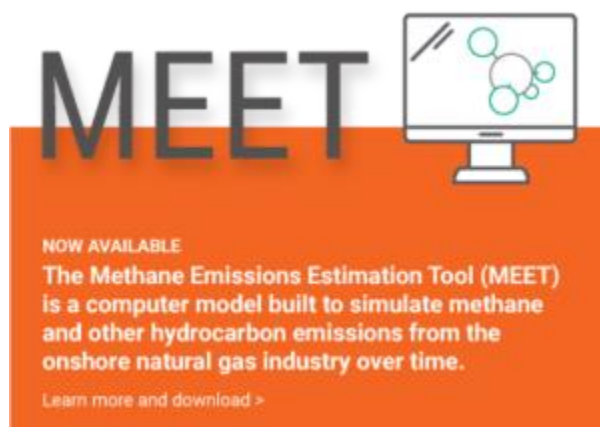
(and many, many others), the sampling frequencies and the resolution thresholds of various instruments, the way to get to the answers we are looking for are from data-driven prediction models. Yes, the measurements are helping analysts to train the models with better understanding of past performance (history matching) and to constrain the models (given more up-to-date inventories and physical constraints) but we are still dependent on models.

One of the most popular models is the MEET model.

Methane Emissions Estimation Tool (MEET)

The state is required to predict emissions as well as enforce permits and collect annual emissions inventory reports for each operator. The MEET model is a commonly used tool to predict future emissions. The **Methane Emissions Estimation Tool (MEET)** is a computer model built to simulate methane and other hydrocarbon emissions from the onshore natural gas industry over time. The goal of the MEET model is to develop a freely available and flexible tool for constructing methane emission inventories representative of several key production areas.

This open-source model gathers emissions and activity data from published research, or from custom data entered by the user, to allow for customization and/or aggregation of emission estimates across a variety of scales. Segments and modules of the model include onshore well sites, compression and boosting, and emissions composition estimation. The results offer an open-source emission estimation tool representative of realistic emission patterns for equipment types – not simple steady state emission assumptions.



The variation of methane emissions at production facilities over time and space is one of the most significant challenges to accurately estimating industry emissions. The MEET model is the first of its kind to enable estimation of emissions with such a high accuracy in time and by source, while being scalable to large producing regions. The tool is modular, customizable and allows users to simulate emissions for a variety of production facilities in any basin that are dynamic in space and time, as well as providing uncertainty estimates.

The model can estimate emissions from either a single facility or multiple facilities in a geographic area. Industry segments in the model include onshore natural gas production, gathering and boosting, gas processing, and transmission and storage. The most fully developed models as of release of this user's guide are onshore production sites and midstream gathering compressor stations.

Developed by the University of Texas at Austin (UT), in collaboration with Colorado State University and SLR Consulting, the source code has been made available as open source hosted by UT. The release of the software comes on the heels of a three-year study aimed at improving estimation of methane emissions by developing

flexible and accurate models using the latest science available. (Allen et al 2022; Zimmerle et al 2022 and Cardoso-Saldana et al 2021)

APCD and MEET, not quite ready for prime time

More from the state's new rule making FAQ document: *“The division is working with the Colorado State University Methane Emissions Technology Evaluation Center (METEC) to develop the Methane Emission Estimation Tool (MEET Model) to help the division better understand methane emissions from oil and gas operations in Colorado. METEC produces the MEET Model in collaboration with colleagues at the University of Texas at Austin. The model uses activity data, production, and equipment counts to estimate emissions from entire facilities, regions, or the basin level.*

The MEET model is a tool that will have multiple uses across the division. One benefit of the model is to evaluate emissions reported to ONGAEIR. Many other potential division uses of the model exist. But the current limitation is that the model needs further refinement to be specific to Colorado. Due to the great potential of the MEET model, the division is invested in making the MEET model as accurate and representative as possible of emissions from oil and gas operations in Colorado.

The division intended to use data reported to ONGAEIR in 2020 and 2021 to populate the MEET model. However, the division has analyzed that data in conjunction with METEC and determined that more than the data reported is needed to update the MEET model to represent emissions from oil and gas operations in Colorado. Based on this analysis, the division updated the 2022 ONGAEIR forms to collect the data required to inform future versions of the MEET model. These items are marked as voluntary for reporting in 2022.

The division encourages operators to complete the voluntary data requirements of the form as thoroughly as possible. The division will continue to evaluate the data collected from ONGAEIR to inform the MEET model and may consider adding additional data or removing the voluntary status as required.”

Other modeling tools

There are other open-source models available to predict greenhouse gas emissions including FEAST and LDAR-Sim. The contract services companies that are developing their technologies using sophisticated data analysis and modeling approaches, some of which are proprietary. A new academic consortium EEMDL has been launched to improve on the current state of methane prediction models.

Fugitive Emissions Abatement Simulation Toolkit - The Fugitive Emissions Abatement Simulation Toolkit or FEAST is a model to evaluate the effectiveness of methane leak detection and repair (LDAR) programs at oil and gas facilities. Recent advances in the development of new fixed (continuous monitoring systems) and mobile (truck-, drone-, plane-, and satellite-based) methane leak detection technologies have led to growing interest in alternative LDAR programs. The FEAST model helps operators and regulators compare a variety of LDAR program configurations such as continuous monitoring systems and hybrid aerial and ground surveys to develop cost-effective mitigation protocols.

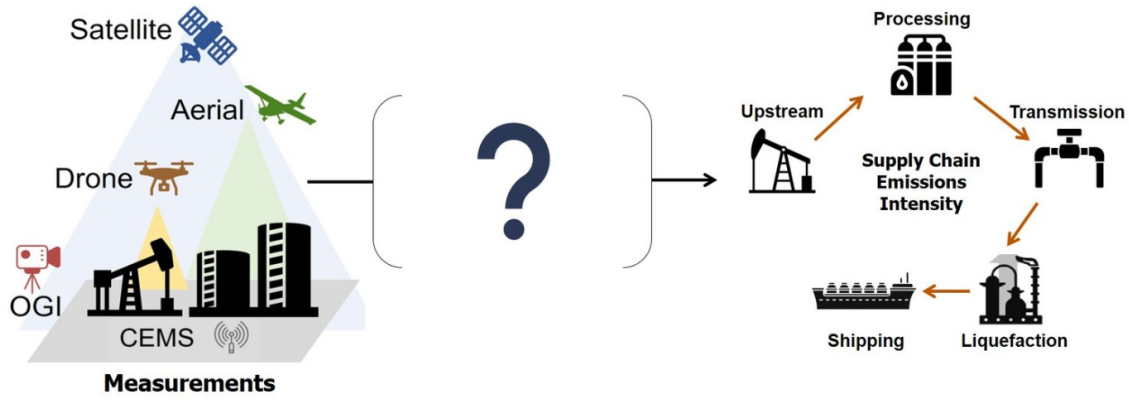
<https://www.arvindravikumar.com/feast/#:~:text=The%20Fugitive%20Emissions%20Abatement%20Simulation%20Toolkit%20or%20FEAST,repair%20%28LDAR%29%20programs%20at%20oil%20and%20gas%20facilities> .

The Leak Detection and Repair Simulator (LDAR-Sim) is an open-source modeling framework for exploring the effectiveness of methane leak detection programs. The purpose of LDAR-Sim is to enable transparent, collaborative, flexible, and intuitive investigation of emerging LDAR technologies, methods, work practices, regulations, and deployment strategies. https://github.com/LDAR-Sim/LDAR_Sim

Energy Emissions Modeling and Data Lab - EEMDL's mission is to provide reliable, science-based, transparent, and measurement-based greenhouse gas emissions assessments of global oil and gas supply chains. The consortium plans to do this through three key approaches: developing community models and tools for greenhouse gas emissions assessments, making publicly available timely, high-resolution emissions datasets, and

creating educational and training materials to enable widespread use of EEMDL's models and data. <https://www.eemdl.utexas.edu/>

Yet, methods to interpret measurements to develop supply chain emissions intensities or measurement informed emissions inventories are elusive.



EEMDL will address this challenge and provide stakeholders standardized ways to interpret greenhouse gas emissions measurement data.

Thoughts on Colorado CDPHE Air Pollution Control Division rule making

Managing Expectations: Can data help build trust?

The heart of the scientific method is to develop a hypothesis (Will people trust measurements and models for methane emissions that they can understand and modify or models they do not understand how they work but were built by people they trust), gather observations and research prior studies and then see if your hypothesis is correct, or maybe you need more data or maybe your hypothesis is wrong and you must redevelop a new hypothesis and try again.

This is the objective of this section. Scientists and analysts would like to believe that data correctly measured and openly communicated can bridge differences of stakeholder opinions but is that the case for the new rule making of verifying methane emissions in Colorado? Our results are inconclusive. Maybe data is only one element to build trust (along with reputation, third party verification and results). When data is just a better estimate as is the case with atmospheric monitoring, and when data is probabilistic (rather than deterministic), is truth probabilistic as well?

One of Data's Many Roles

In today's world, data has become an essential element of decision-making in virtually all areas of life, including business, healthcare, and government. Data analysis and interpretation have proven to be effective tools in solving problems, improving efficiency, and making better-informed decisions. One area where data is becoming increasingly important is in building public trust. In industries like oil and gas, public trust is critical for maintaining a social license to operate. Without the trust of the communities in which they operate, companies in the industry may face significant difficulties in obtaining permits, attracting investment, and maintaining a positive reputation. However, the extraction and processing of fossil fuels have long been associated with environmental harm, and communities have become increasingly skeptical of industry claims about environmental performance. To rebuild public trust, oil and gas companies are turning to data to

demonstrate their commitment to sustainability and to improve their environmental performance. In Colorado, the oil and gas industry is subject to comparatively tighter regulations that require them to report their greenhouse gas emissions, water usage, and waste disposal which are collected, verified, and publicly reported to create a level of transparency to all stakeholders.

The use of data to build public trust is about more than just compliance with regulations or improving environmental performance. It is about demonstrating a commitment to transparency, accountability, sustainability, and working collaboratively to address environmental challenges and local community concerns. To be effective, the data must be accurate, reliable, and trustworthy. This requires companies to invest in rigorous data collection processes, independent verification, and public reporting mechanisms. Companies can engage with stakeholders to understand their concerns, provide meaningful opportunities for input, and respond to feedback.

By using data effectively and engaging with stakeholders, oil and gas companies could build more public trust and secure a social license to operate. Public comments regarding the intensity verification for greenhouse gas emissions reporting focus on improving the accuracy and reliability of the measurement and verification of operators' emissions. Recommendations include 1) setting minimum and maximum requirements for measurement and emission monitoring with respect to repeatability and reconciliation 2) provide recommendations and requirements for determining relative thresholds in the uncertainty of monitoring methods. While there may be concerns about the feasibility of implementing specific verification programs for existing and new facilities, it is crucial to establish minimum requirements and standards for emission reporting and monitoring to ensure the integrity of the process of emission reduction. By doing so, operators can prove their emission reduction efforts and ultimately produce energy in a trustful and transparent way.

Time and Faith

The opinions of people in Colorado about the oil and gas industry are varied and complex. Some individuals and groups support the industry, seeing it as a vital part of the state's economy and a source of well-paying jobs, while others are concerned about the environmental and health impacts of oil and gas operations, such as noise, air, water pollution, and the potential for accidents or leaks. In recent years, there has been significant debate and controversy in Colorado over the regulation and development of the oil and gas industry. In 2019, Colorado passed a sweeping overhaul of oil and gas regulations, known as Senate Bill 19-181, which prioritizes public health, safety, and the environment in the state's regulation of the industry. The bill has been praised by some as a necessary step towards protecting public health and the environment, while others see it as a threat to the industry and the jobs it supports.

Adoption of new practices in any industry can be a slow process, particularly if there are established ways of doing things that have been in place for a long time. However, the urgency of the need to address environmental and social concerns associated with the extraction industry, such as climate change and community impacts, can create pressure to adopt new practices more quickly. Currently, Colorado's oil and gas regulation is moving at a faster pace on making operational requirements or limitations than the industry can handle. Adoption of new practices in extraction industries will depend on a range of factors, which all impact the time needed to get to the point of satisfaction for all stakeholders.

While this may put more pressure on the operators, it urges the oil and gas industry to move in the right direction in sustainable development. This is where faith, in terms of the value and effectiveness of new practices, can also play a role for all operators and communities. If all industry stakeholders have faith in the benefits of new practices and that these efforts take time, each party may be more likely to adopt them. This is where data can provide evidence supporting the effectiveness of the new practices. What should the data look like or say? At this point is it unclear on what data would build more trust in sustainable oil and gas development in Colorado. It seems that community members would like to see consistent proof that operations are meeting

the requirements of the community, the environment, and the regulators while also reducing overall emissions. This will take time and community members should have faith but also keep the industry accountable by becoming involved and expressing their concerns before operations begin or as they develop.

Can Colorado meet greenhouse gas reduction goals while still drilling new wells and operating existing ones?

The state is facing a difficult balancing act in addressing public concerns over greenhouse gas emissions, enacting regulations specified by legislative action and allowing the oil and gas industry to continue to supply fossil fuels that modern economies are demanding. The new rule making will be another tool for the state to attempt to maintain this delicate balance.

Production Decline in unconventional reservoirs

If the oil and gas industry were to stop drilling for oil and natural gas today, the production of unconventional resources in the Lower 48 states would see a significant decrease. In fact, according to data from Novi Labs, new horizontal wells made up 46% of total oil and gas production by the end of 2022, which is a noticeable shift from previous years. In 2018, new wells accounted for 56% of total production, and in 2014, they accounted for 64%. Despite the industry facing challenges such as parent/child well simulation issues, lower high quality drill site inventory, and maturing fields, larger completion treatments and better reservoir management have resulted in only slightly lower decline rates.



Figure 1: What would happen if we stopped drilling today (Cross, 2023).

In his report, Hendrickson estimated the decline rate for each basin in the US (Figure 2). The first-year decline is the reduction in production that he predicted would occur if all drilling stopped at the beginning of 2020. Niobrara had the highest reported decline rate at 53%.

Shale Plays	Estimated YE2019 Oil Production Rate		First-Year Decline
	MMbbl/d	% of total	Annual %
Bakken	1.5	12%	42%
Alaska North Slope	0.4	3%	9%
Central Basin Platform	0.3	2%	19%
Delaware	2.3	18%	42%
Eagle Ford	1.3	11%	48%
Midland	1.9	15%	45%
Niobrara	0.6	5%	53%
SCOOP	0.2	2%	39%
STACK	0.3	2%	48%
Remainder	3.7	29%	15%
Total	12.6		34%

Figure 2: First year decline rates (Hendrickson, n.d.)

So, if we ban drilling it won't take very long to see a significant production decline and we will be moving away from the much-lauded energy independence that the shale revolution brought the United States and back into a situation of importing much of our fossil fuel energy (or replacing it with renewables if possible).

Public Concerns

The public comment sessions held by the Air Pollution Control Division have been very useful to collect the opinions of a large section of stakeholders. From our perspective several important themes were voiced at the public hearing on 12/7/2022 from several public/community groups. Those themes include:

- Need for accurate, direct measurements, not estimates
- Need for timely, site-specific data, but the state inventory process only gives you one data point a year and one snapshot of the entire industry, communities want a rapid response to any incident and do not have a good understanding of the lifecycle (when you measure) of emissions
- Need for independent verification (from CDHPE or third-party), not operator self-reporting
- Need for transparency and prompt response to complaints
- Rapid reduction of methane emissions (no time to wait)
- Desire by some for direct regulations of technology by state
- A lot of concern about health issues regarding ozone/air quality, there seems to be some confusion between the impact of methane and the more obvious local immediate (smog every day in the summer) of ozone

From the public hearings there have been other questions from citizens. Here are a couple of additional comments and concerns that bring out the level of detailed interest in the rule making.

“Why has the state not spent the money to independently monitor a couple of well pads from pre-drilling through production to accurately establish the emissions from the process? Emphasis on independent.”

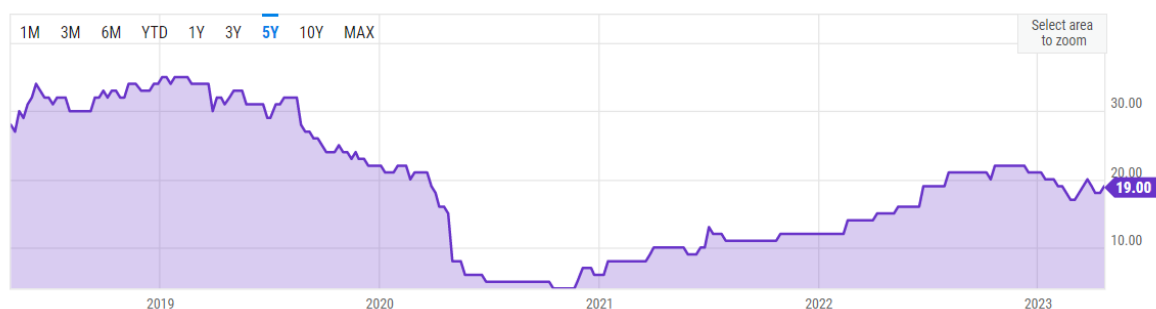
“Would you please address the incorrect Global Warming Potential factor used in the State’s GHG Roadmap? The factor used in the roadmap is 25 which is the factor to convert methane to CO2 equivalent over 100 years. But the impact of methane is much more potent over a shorter time period (10-20 years). A more accurate, but still conservative factor, is 86 (GWP for 20 years). If this more accurate factor is used, emissions from oil and gas industry surpass transportation and the focus is put on the correct entity.”

“Wells are permitted through the COGCC. Pollution from the well pads is not considered until drilling begins. The APCD under current rules cannot not impact well permits. But the law says public health, safety, the environment must be protected. How can this happen if the pollution is not considered in the permitting process?”

These are tough asks!

Current Industry Activity in Colorado

Companies in Colorado pumped 152 million barrels of oil in 2021, according to data from the Colorado Oil and Gas Conservation Commission. That is the lowest production since 2017, and more than 20 percent off record numbers in 2019. The number of drill rigs drilling new wells in Colorado jumped from eight in March 2021 to 14 at the end of March 2022, according to Baker Hughes. The number of rigs is still fewer than half the 33 that were drilling in March 2019. There were 19 drilling rigs active in Colorado as of the week of April 21, 2023. There are 377 drilling rigs active in Texas this same period.



https://ycharts.com/indicators/colorado_inland_rotary_rigs#:~:text=Colorado%20Inland%20Rig%20Count%20is,26.67%25%20from%20one%20year%20ago.

Under the new, more strict rules, that went into effect last year, the state says up to 227 new wells have been approved across 15 different oil and gas development plans submitted by drillers. One plan was rejected, which included 33 wells.

Permits are only part of the story. Even if the industry wanted to ramp up production, there may not enough workers to operate the rigs and wells. Note the industry response to the crude oil price crash in the second quarter of 2020. Many workers and equipment left during the pandemic slowdown. Mining and Logging employment in Colorado is down by about 10,000 workers, from 29,000 in 2019 to 19,000 in 2022, the lowest number of workers since 2006.

Well production depends on many factors from reservoir quality to completion design. There is no such thing as an average well except in statistical analysis. Improving completion techniques that involved longer lateral length, proppant and fluid loading as well as a better understanding of the reservoir quality of the target zones in the Niobrara formation can lead to the need for fewer wells for a target production level. Modern “super-pad” drill sites enable more efficient drilling and completion as well as next generation production facilities designs and lower methane emissions. Swapping older legacy wells for modern ones will improve productivity

measures but the rapid decline curve of unconventional reservoirs will still be the deciding factor as well as commodity prices.

Three new CAP applications (Comprehensive Area Plans) were approved by the COGCC in 2022 including the Guanella permit (PDC) in Weld County, the Box Elder permit (Crestone Peak) in Adams County and the Bronco permit (Occidental) in Weld County. In addition, Chevron has been given approval for their Wells Ranch permit also in Weld County. Environmental groups are getting concerned about the cumulative impact of approved drilling permits since the regulatory overall in 2019 as more than 1400 drilling permits have been approved by the COGCC since early 2022. Most of these permits are in Weld (DJ Basin), Rio Blanco (Piceance Basin) or La Plata (San Juan Basin) counties.

Drilling and production of oil and gas will always be dependent on commodity prices, state regulations and availability of infrastructure (drilling rigs, crews, pipelines). But it seems that while the oil and gas industry has recovered from the COVID demand destruction and have adapted to the stricter new state regulations, oil and gas production in the state is at a plateau. What path state production will take depends on many factors.

Greenhouse Gas emissions are falling but meeting the new targets in 2030 will make it difficult to balance the goals of the state's Net-Zero Roadmap and the industry's objectives to maintain production without an emphasis on next generation production facilities (greater production volumes with significantly lower emissions) and on greater monitoring and measurement of GHG emissions. The nature of unconventional wells (such as the Niobrara play in the Wattenberg Field in the DJ Basin) requires new drilling to offset rapid decline so new drilling permits and practical limits on emissions from production will have a significant impact on future production forecasts. We will discuss how these new regulations impact smaller producers in a following section.

How will Colorado align with new US EPA regulations?

Colorado has always prided itself with being a pace-setter in environmental regulations. But now the federal government and other states are making significant moves to catch up. The Environmental Protection Agency announced a rule in November 2022 following up on a proposal President Biden announced last year at a United Nations climate summit in Scotland (COP16). The 2021 rule targets emissions from existing oil and gas wells nationwide, rather than focusing only on new wells as previous EPA regulations have done.

The Environmental Protection Agency's upcoming Quad Ob and Quad Oc emissions monitoring rules, expected to be implemented in 2023, will expand the scope of compliance to more oil and natural gas production sites and include requirements based on site size rather than emissions levels. The regulations prioritize capturing and using gas on-site, with flaring only allowed as a last resort, subject to stringent regulations and requirements. There is also the new SERP rule (super-emitter response program) that will allow third parties such as environmental groups to monitor for leaks using remote sensing technology and report those leaks directly to operators, potentially triggering corrective action in accordance with the EPA methane standards under the Clean Air Act.

The EPA's supplemental proposal, Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources, better known as New Source Performance Standards, Subpart OOOOb and OOOOc. The proposed rule, as drafted, includes the following:

- Routine leak monitoring at all well sites and compressor stations;
- Continued leak monitoring at abandoned and unplugged wells, including a final leak survey once a well is permanently closed;
- Creation of a Super Emitter Response Program (SERP) to detect and report (through a 3rd party) emissions exceeding 100 kg/hr;

- Increased stringency for flares, including flare performance, monitoring, and minimal ability to flare associated gas;
- Install or retrofit pneumatic pumps to have zero emissions;
- Emissions Guidelines for states to develop and implement complementary rules to existing locations;

The new rule goes a step further than previous federal regulations and takes aim at all drilling sites, including smaller wells that now will be required to identify, locate, and plug methane leaks. Small wells currently are subject to an initial inspection but are rarely checked again for leaks.

Besides the EPA rule, the climate and health law approved by Congress in August, 2022 includes a methane emissions reduction program that would impose a fee on energy producers that exceed a certain level of methane emissions. The fee, set at \$900 per metric ton in 2024 and to rise to \$1,500 per metric ton of methane by 2026, marks the first time the federal government has directly imposed a fee, or tax, on greenhouse gas emissions.

There are exemption limits for onshore and offshore gas production of 0.2% of gas sent to sale and for onshore and offshore oil production of 10 metric tons of methane per million barrels of oil produced. How does this compare with today industry performance you might ask? A recent study by Rutherford et al (2021) estimates that methane emissions from 2015 dry gas production was 1.6% (not 0.2%). A study from Zhang et al, 2020 estimated that the Permian Basin production in 2018 had methane emissions of 2250 metric tons of methane per million barrels of oil produced (not 10 metric tons). Another study (Ayasse et al 2022 Environ. Res. Lett.) estimated that the methane emissions from production facilities in the Gulf of Mexico was 5,000 to 30,000 metric tons per million barrels of oil produced. Houston, we have a problem and a big bill could be on the way for the industry starting in 2024.

Today the EPA's rules for 40 CFR 98 Subpart W greenhouse gas reporting program (GHGRP) are emissions factor data from spreadsheet with no operational measurements required. In the new proposed regulation (Sec 60113 (h)) it states that "*not later than two years after the date of enactment of this section, the Administrator (EPA) shall revise the requirements of subpart W . . . to ensure the reporting under such subpart and calculations of charges (the methane fee) . . . are based on empirical data.*" Just what empirical data means is not defined but this change could be revolutionary.

The law allows exemptions for companies that comply with the EPA's standards or fall below a certain emissions threshold. It also includes \$1.5 billion in grants and other spending to help operators and local communities improve monitoring and data collection for methane emissions, with the goal of finding and repairing natural gas leaks.

New Funding for methane reduction research programs

The United States is also providing funding for novel research programs in methane reduction technologies. The U.S. Department of Energy (DOE) recently announced nearly \$47 million in funding for 22 research projects to advance the development of new and innovative measurement, monitoring, and mitigation technologies to help detect, quantify, and reduce methane emissions across oil and natural gas producing regions of the United States.

DOE's methane mitigation program addresses critical environmental issues associated with the production, transmission, and storage of domestic oil and natural gas. Projects will focus on technical challenges of quantifying and mitigating methane emissions along the U.S. oil and natural gas supply chain, including the development and demonstration of an efficient integrated methane monitoring platform to enable early detection of methane emissions. DOE's Office of Fossil Energy and Carbon Management (FECM) will manage the selected projects.

The selected projects will advance cutting-edge technologies under five areas:

Mitigating Methane Emissions from Upstream/Midstream Sources – Projects will address mitigating methane emissions from engines and machinery used in the extraction and production of natural gas and oil to advance the development of cleaner fuels for the industry.

Surface-based Methane Monitoring and Measurement Networks – Projects will gather and compile surface-based methane emissions data and appropriate wind speed and direction measurements to effectively characterize methane sources and emission rates across a broad area that includes multiple operators of oil and gas production facilities.

Basin-Specific Needs to Mitigate Methane Emissions – Across the United States, oil- and gas-producing basins have characteristics that require unique approaches to resource production, transportation, and storage. Projects will demonstrate methods to measure and quantify methane emissions along the natural gas supply chain focusing on basin-specific requirements.

Integrated Methane Monitoring Platform Design – Projects will aim to develop integrated methane monitoring platforms to continually collect and analyze methane emissions data across the natural gas supply chain to characterize methane emissions from chronic and super-emitters and inform near real-time mitigation decisions.

Investigating Emissions from Storage Tanks – Projects will work to identify the primary sources of methane emissions from storage tanks and their associated equipment across the oil and natural gas value chain and evaluate monitoring technologies.

<https://www.energy.gov/articles/doe-invests-47-million-reduce-methane-emissions-oil-and-gas-sector>

Will Colorado lead, or influence other states/regions/EPA or is it just a special case?

The State of Colorado is a national leader in its commitment to fostering safe and responsible development of Colorado's oil and gas resources. Over the past twelve years Colorado has implemented precedent-setting regulations from baseline groundwater testing and monitoring to air regulations targeting methane leak detection and repair.

On April 16, 2019 Governor Jared Polis signed SB 181 into law. This landmark legislation increases regulations on oil and natural gas development and operations in Colorado, with a focus on public health, safety, welfare, the environment, and wildlife resources. Senate Bill 181 is the most comprehensive oil and natural gas legislation Colorado has seen in decades. The passage of SB 181 was the beginning, not the end and the ultimate impacts will be determined by many complicated regulatory rulemakings at both the state and local levels, which will take years to complete. The current rule making we are studying is just one of those steps.

Colorado was the first state in the nation to enact leak detection and repair (LDAR) regulations in 2014 to reduce methane emissions. In December 2019, those rules were made more rigorous by the Air Quality Control Commission and are the toughest air regulations in the country.

But at the Federal Level (EPA)

As described earlier, the Environmental Protection Agency has announced a new Proposed rule for reporting methane and GHG emissions. The new rule is called “Standards of Performance for New, Reconstructed and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (86 Fed. Ref. 63110). Quite a mouthful.

First let us look at a little history of the EPA regulations as described by Ryan Streams of Highwood Emissions Management (Streams, 2022): “Released in 2015, the OOOOa rule was the first serious attempt to address methane emissions directly from US oil and gas production at the Federal level. It was revolutionary in its embrace of what at the time was “cutting edge” technology – the handheld optical gas imaging camera, in addition to Method 21 methane concentration analyzers. The rule defined leaks based on parts per million (ppm), and was a reflection of our understanding of methane at the time. In 2018, there was another rulemaking to “modernize” parts of the OOOOa rule, creating things like a better pathway for EPA to review more advanced technologies like remote sensing systems to find and fix methane leaks. Many celebrated, because EPA appeared to open the door to relaxing its requirements for new methane detection technology approval. Now, multiple sites could be covered by an alternative technology application, instead of requiring every single wellsite to go through the federal notice and comment process. It was progress, albeit agonizingly slow and incremental.

Today, EPA’s proposed rules look nearly unrecognizable alongside that first OOOOa rule. From the ringing support of alternative technology, to the end of emitting pneumatic devices, and the complete overhaul of processes like liquids unloading, EPA rules have rocketed forward in terms of their stringency, yes, but also their sophistication, as knowledge of emissions has grown.

The current EPA rules look like policy that was crafted with a careful eye on the state of the science of methane emissions. In 2014 and 2015, when the OOOOa rules were being developed, technologies like the ones used to quantify basin-scale methane emissions were a distant dream. Now, we have millions of measurements pouring in each year from satellites, aircraft, drones, and continuous sensing platforms. We’ve had groundbreaking papers published that upended the conventional wisdom about the size and nature of methane leaks. The science of methane had its renaissance – the question was if and when the policy of methane would have its own.

The current proposal by EPA is not without its controversy. It’s unquestionably a tough rule in many respects. The oil and gas industry will need to make significant investments in order to comply. And, of course, there will always be voices pushing us to go farther. As we all dig into the public comment process and work with stakeholders, it’s important we continue to push the boundaries of science and policy. But just as important, we ought to take a moment and recognize the tremendous strides made by the community that’s so deeply focused on understanding methane emissions. Without that work, it’s easy to imagine a methane rule today that would look drastically different from the one we have, where leaks are still measured in ppm, new technology is ignored, and we follow that pace of agonizingly slow improvements. The staff at EPA deserves credit as well – the methane mitigation industry has been moving at a breakneck pace, and digesting it all to create coherent policy is no easy task.” (Stazzone, 2023)

Where is the next state or province to adopt new regulations after Colorado and Alberta. Is New Mexico next? Despite the ongoing shift towards cleaner energy sources, fossil fuels will remain a cornerstone of national energy consumption for at least the next two to three decades, maybe longer. This reality, however, underscores the pressing need to tangibly demonstrate emissions reductions. In the New Mexico Permian Basin, measurements of emissions have soared to an alarming 6.5x higher than reported figures as oil production grows, with a staggering 9.4% of total production loss in the New Mexico part of the Permian Basin alone. Confronting this challenge requires prioritizing methane measurement and reduction projects, while emphasizing those with shorter cycles and significant abatement potential. (Chen, et al 2021)

On May 25, 2021, New Mexico’s EMNRD (Energy, Minerals and Natural Resources Department) published its new rules which limit most venting and flaring of natural gas as part of New Mexico’s mission to reduce methane emissions. The rules are now in effect and are viewable in the New Mexico Register. The rules are adopted pursuant to the Oil and Gas Act and apply to persons engaged in oil and gas exploration within New Mexico.

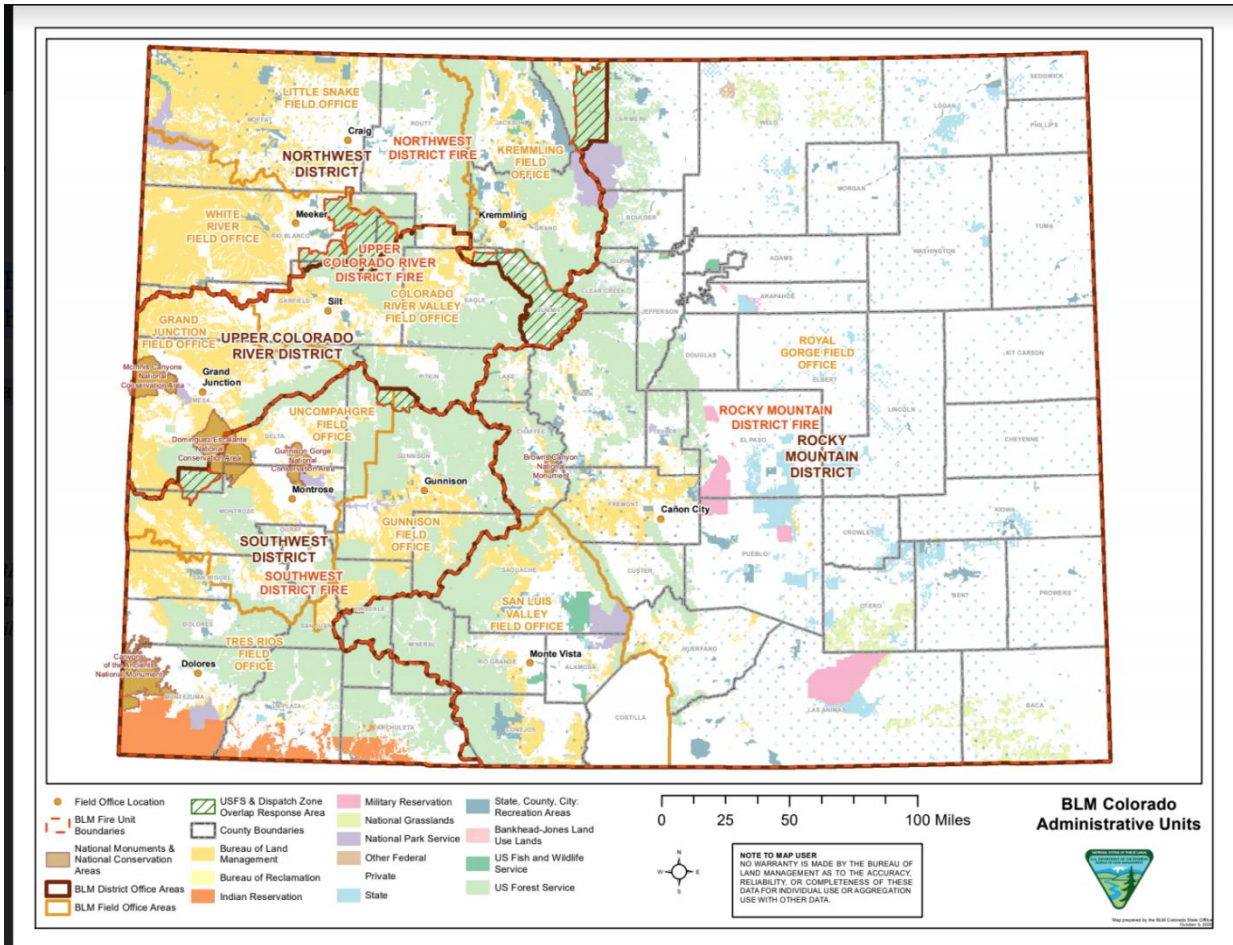
The EMNRD’s published regulation at 19.15.27.8 NMAC declares venting and flaring of natural gas to be waste and prohibits it with limited exceptions. Those exceptions are different for each phase of operations: drilling, completion or recompletion, and production. There are a few exceptions to the general prohibition against venting and flaring, but other applicable state and federal laws can alter the rights of operators by narrowing the exceptions. The regulation requires operators to use system and equipment components that are

designed to minimize the escape of natural gas, and the requirements for these components vary depending on when they were installed or replaced. Operators may need to conduct routine AVO (audio, visual, and olfactory) inspections, the frequency and necessity of which depend on several considerations, including well production capacity, whether the operator is on site, and whether there is a remote or automated monitoring technology to detect leaks and releases in lieu of inspections. Operators must measure and report instances of venting and flaring to the EMNRD monthly, and must make the records available for inspection by the EMNRD upon request. In addition to the monthly reporting forms, particular occurrences of certain types and quantities of venting and flaring mandate the operator to notify the EMNRD, and the procedure for communicating such releases varies depending on the type and quantity. Extra reporting requirements apply for wells or facilities in which the state owns a royalty interest. <https://www.modrall.com/2021/06/17/update-on-new-mexicos-methane-rules/#:~:text=A%20few%20weeks%20ago%2C%20on%20May%2025%2C%202021%2C,and%20are%20viewable%20in%20the%20New%20Mexico%20Register.>

A Patchwork of Regulations:

While it is obvious that many regulatory agencies are moving forward with new rules on methane emissions from upstream and midstream oil and gas production, processing, and transportation it is also clear that most of these agencies are taking slightly different approaches. This is not a surprise given the overall federal/state governance philosophy that exists in the United States, but it does lead to a patchwork of regulations for an oil and gas operator to navigate and comply with. The impact of new rule making will be different state to state.

In Colorado the impact of different basins such as the Denver Julesburg (DJ) Basin versus western slope Piceance or Uinta Basins due to the large percentage of federal land in the western part of the state. The western half of Colorado has joint state and BLM/BIA/Forest Service oversight on oil and gas operations. The same goes for the San Juan Basin in the southwestern part of the state due to the Ute Tribal Lands covering that basin. As of now there is no solution to this patchwork of regulations as it falls on each operator to know the rule (and often rules) that they must operator under. While most regulatory attention has been put on the DJ Basin, the new rule making covers every operator regardless of where their operations are. The APCD is starting to gather data and build models for areas outside the DJ and we will see just how different the emissions profiles are. The rocks are different. The operations and infrastructure are different. So, you can probably anticipate that specific emissions models developed for the DJ Basin will have to be modified to fit operations in other parts of the state.



As an example, here is what the BLM is responsible for: The Bureau of Land Management manages 8.3 million acres of public land in Colorado that support a wide variety of topographic, climatic, geologic, and hydrological conditions. The state of Colorado is nearly 66.6 million acres in size, supporting these diverse plant habitats at elevations spanning 3,315 feet to 14,431 feet. Most BLM-managed public lands fall within the western slope of Colorado.

Impact of new rule making on stripper production and small producers

A recent research report by the Environmental Defense Fund (EDF) (Omara, et. al, 2022) highlights the challenge of keeping track of greenhouse gas emissions from all potential oil and gas producing sites, especially on the large number of oil and natural gas production sites with low production rates and the possible large contribution from these sites to the total impact of the oil and gas sector methane emissions profile. New production sites will mostly have larger production and a greater economic incentive for the operator to install more modern production equipment, continuous monitoring for air and water quality emissions, more automation and remote monitoring capabilities which usually result in a lower methane intensity behavior. But what about the industry’s legacy footprint and smaller operators?

To quote from the Omara report: *“Eighty percent of US oil and natural gas (O&G) production sites are low production well sites with average site-level production <15 BOEG per day and producing only 6% of the nation’s O&G output in 2019.”* In their study, they integrated national site-level O&G production data and previously reported site-level CH4 measurement data and concluded that low production well sites are a disproportionately large source of US O&G well site CH4 emissions, emitting more than 4 tera-grams (95% confidence level (3-6), 50% more than

the total CH₄ emissions from the Permian Basin, one of the world's largest O&G production regions. They estimate low production well sites represent roughly half (probability of between 37-75%) of all O&G well site CH₄ emissions and a production-normalized CH₄ loss rate of more than 10% - a factor of 6-12 times higher than the mean CH₄ loss rate of 1.5% for all O&G well sites in the US. Their work suggests that achieving significant reductions in O&G CH₄ emissions will require mitigation of emissions from low production sites as well as large production sites.

While this observation suggests that the production well sites that are easiest to get the best data from, are the one that are not really the significant problem. So, you might conclude that the problem falls on the small producer with the marginal or stripper production wells but the data suggests otherwise. The EDF study goes on to find that most of the low production well sites (77%) are owned by the largest producers. While there is regional variability in this ownership profile, regulators can look to the most capable large producer to be responsible for the reporting of a large portion of the low production sites. To this end, several new drilling and production permits in the DJ Basin by the largest producers include a commitment to abandon and reclaim older production well sites and eliminate the methane emissions from these sites.

The new Colorado state rule making does differentiate the impact on majority producers (top 80%) versus minority producers (bottom 20%) in their proposal. But when you add in the action of the EPA, confusion, and uncertainty reign when it comes to the pending methane emissions tax included in last year's Inflation Reduction Act. There is concern that the tax will most heavily impact mid-size independent producers, those below 25,000 tons of CO₂e emissions will be exempt and larger producers will probably have technology monitoring solutions in place to accurately measure their emissions but there is a sector of the industry in the middle.

As we have discussed in this paper, there are issues of how emissions are supposed to be calculated. Though smaller operators may report emissions well below that threshold, factoring in gathering and boosting facility emissions can put them over the threshold. Then there is the question of emissions being calculated in tons while natural gas sales are calculated in volumes. Mid-size companies may have good equipment controllers to contain emissions, but because of sales, they are now subject to the tax.

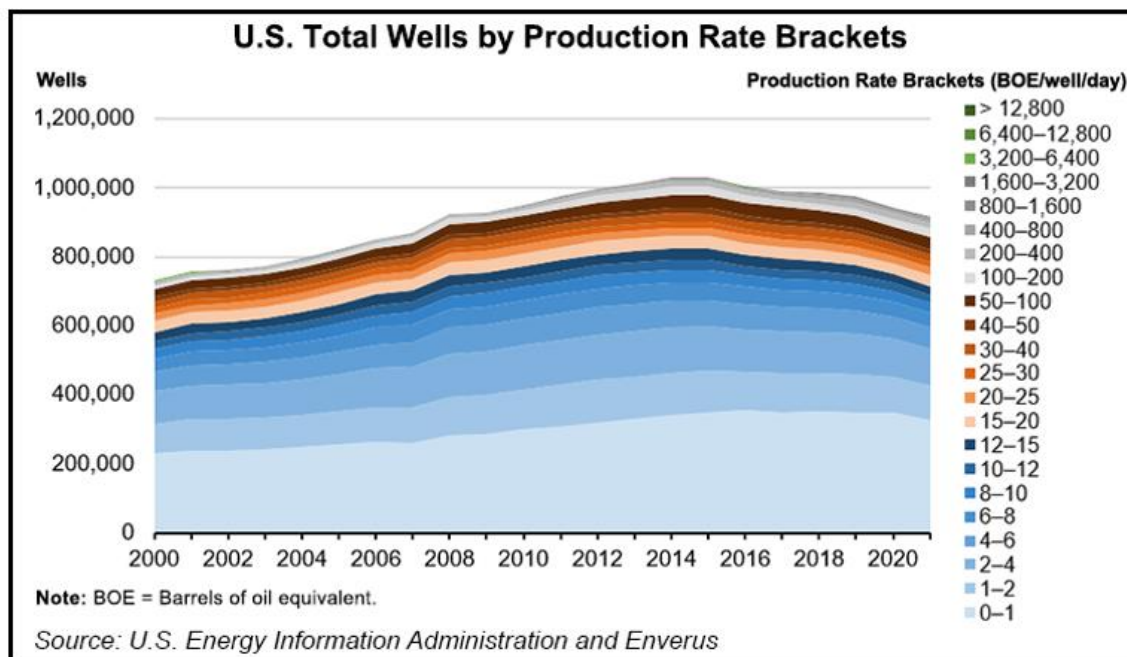
Back to the Omara study, from a small number of studies (only 6) on a small sample of low production well sites (only 240) out of the large number of wells in the US that are low production well volumes (565,000 out of a total of 800,000 active wells in 2019, the EDF study developed a profile of top 5% of well sites in the high-emitting category, the bottom 95% of well sites with detectable but low-emitting behavior and a third category for wells in the below-detection threshold limit behavior. This profile represents the "heavy tail" characteristic found in most studies. The high-emitting well sites CH₄ emissions are equivalent to >13% of total natural gas production. This CH₄ loss rate is higher than the mean CH₄ loss rate for all O&G sell sites based on other research studies. The profile will be different based on regional production practices and operations history (i.e., as many as 90% of all wells in the Appalachian basin falling into the low-production category and an estimated 1.3 Tg. out of the total 4 Tg. of CH₄ emissions located in this region). The study of the DJ Basin low-production well sites suggest it is one of the lower emitting basins in the US.

Whether you believe this modeling or not, the high-emitting but low production well sites are a significant element of the industry methane emissions profile and need to be accounted for in some pragmatic manner. This also applies to the orphan well category of well is that often poorly documented. The fact that most of these wells are owned by the largest producers will help regulators focus on a group of operators that in many cases are already trying to deal with the issue. Many of these low-production well sites are kept active to hold lease positions is a negotiating point for operators looking to apply for new drilling and production permits and will properly abandon and reclaimed legacy well sites as part of a new comprehensive area planning permit.

With modern production facilities and older wells being reclaimed, it is a win-win approach for all stakeholders. But the regulations do not impact all the sectors of the industry in a similar manner.

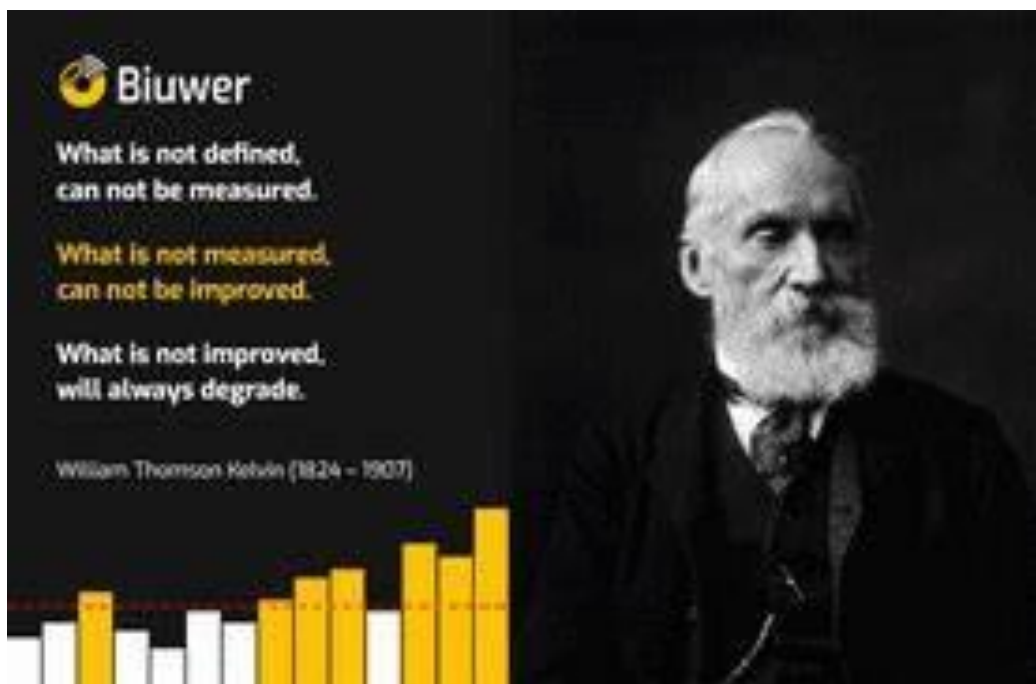
Lower 48 Producing More Oil, Natural Gas from Fewer Wells

In a separate report by the Energy Information Administration (EIA) based on Enverus data, an increasingly small percentage of oil and natural gas wells is supplying the majority of U.S. production. The total number of producing wells in the United States declined by about 11.1% from a peak of more than 1,031,183 wells in 2014 to about 916,934 wells in 2021, EIA researchers said. U.S. oil production rose by 28% over the same span to average 11.25 million b/d in 2021, versus 8.79 million b/d in 2014.



According to EIA, 77.9% of U.S. wells produced less than 15 boe/d in 2021, while only 6.4% of wells produced more than 100 boe/d. However, wells producing 100 boe/d or more supplied 75% of oil production and 74% of natural gas production in 2021. By comparison, in 2011, the 100 boe/d or more well category supplied 57% and 55% of oil and natural gas production, respectively. Horizontal wells accounted for 89.5% of the wells that produced 100 boe/d or more in 2021, up from 52.7% in 2011. The EIA team noted that marginal wells nearing the end of their economically useful lives, aka stripper wells, produced about 7% of total U.S. oil and natural gas in 2021. The Internal Revenue Service defines a stripper well as one that produces 15 b/d or less of oil, or 90,000 cubic feet/d or less of natural gas, over a calendar year. Stripper wells supplied 16% of oil and 14% of natural gas output in 2011. (NaturalGasIntel, 2023)

Conclusion



As a summary, the new rule for methane emissions verification reporting is an important step in the journey towards a comprehensive understanding of the industry sector methane emissions, but it is not the end of the journey. After all, the approach still is based on engineering factor estimations not direct, facility site-specific or source-specific measurements of GHG emissions. The use of a methane intensity metric is supported by industry but is a subject of disagreement with environmental activists.

It was clear from the public comments that many speakers were expecting the state to respond to community concern with direct measurement, accurate, site-specific, and real time reporting for local communities. This expectation is still far too ambitious for the regulatory agency, the oil and natural gas industry (even the best operators) and the current state of the measurement technology. Methane measurement is a complex topic that is evolving rapidly. The technical and statistical details are not easy to communicate to the public. There is a heightened awareness that actions to reduce methane emissions are needed now but this ruling is only one part of the regulatory and industry best practices response.

Some voices are urging the process towards net- zero decarbonization to accelerate, other are suggesting we are already moving too fast. Which one is right? Some environmental activists have asked to rename natural gas to either methane gas or fossil gas to present a more negative impression. But what if you called wind and solar as intermittent renewable energy and geothermal and hydro as renewable energy would that bring more clarity or more arguments?

Our research talked to and more importantly listened to all sides for this study. After considering the significant implications of this move towards measurement-informed inventory reporting, it is our conclusion that the state is making an important step in the right direction but that it is likely to face serious hurdles in execution.

Hurdles that come in the form of:

- 1) the need to grow data analysis capabilities, both in its state regulatory staff and in operators, contractors, and auditors,

2) in public perception of what the new rules will mean and

3) in adequate incentives for many (but not all) oil and gas operators to adapt to the new rules and reduce emissions.

The measurement informed emissions inventory (MII) will be more accurate and the under-reporting will be less and better segmented, but the nature of the oil and gas production process, economic considerations (lack of a market signal) and the uncertainties that still exist in the digital technologies will have the result still wanting from the ideal. The papers from CSU (Bell 2022) about the differences in measurement techniques is telling. There is still a lot to learn. But that is not a reason not to continue along this measure what matters journey.

As said previously the new rule making is a step in the right direction. If expectations are managed (which will be a challenge in itself) then the MII step the CDPHE APCD is taking will be a constructive and practical one. But technology is evolving, the industry is divided and the public concern is often too ambitious and struggles to understand practical field challenges and data analysis assumptions and constraints. The truth at this moment is probabilistic not deterministic. There is still no single answer to methane emissions and trust is in short supply. We anticipate that there will be arguments over data measurements, over annual company submissions, over the timeliness of reporting and many other aspects of this new rule. The court room is not the best place to try and resolve these disagreements, but it is likely many of them will end up there.

New regulations require a “break-in” period for all the stakeholders to fully understand the new rules and methods. The APCD is planning for a “compliance-assistance” period of a couple of years in working with the industry sector before moving onto a “compliance-enforcement” approach. This is a practical approach but many environmental activists do not think the planet has much time to reduce emissions.

This rule making will produce a more accurate and verifiable inventory, not specific methane reductions. That will be accomplished by the changes in operations driven by a greater degree of transparency (and public pressure, “name-and-shame”) and proactive operators’ investment (message from the market) and operations “best practices” improvements around environmental stewardship that will reduce methane and other greenhouse gas emissions. One supports the other, but we are not sure the expectations from public influencers get this point yet.

It seems that the best choice of a top-down measurement perspective for the state regulatory agencies at this point is a satellite-based data benchmark, maybe with aerial surveys to validate basin emissions from a more local perspective. However, the staff in the state agency are more familiar with aerial surveys. Several university research groups and a few specialized data analytics firms focus on images from satellites.

The EPA is also getting into the act. Perhaps it is no coincidence that the Congressional Research Service (CRS), in outlining the key points of the IRA, noted that charges soon to be levied on methane emitters represent the first time ever that the federal government has directly imposed a charge, fee, or tax on GHG emissions—not long after the view from space began to bring the methane issue into better focus. Therefore, the top-down measurement will be from space, or at least from the view from an aircraft-based survey. The CDPHE has already flown its first aerial survey in 2021 and recently hired its first program manager for future surveys.

According to several consultant studies (for example: Highwood Emissions Management) there is a larger performance gap between the top operators who are proactively addressing methane emissions, updating their bottom-up equipment-based inventory with practical operational and measurement methods and are already achieving the lower emissions targets being discussed versus traditional producers who are just trying to keep up with the changing patchwork of regulations (federal, state, community) and trying to stay alive when commodity prices are low. These new rules will be hard on this class of operators.

Given this diversity of responses, it will place a difficult challenge on Colorado regulators to come up with their proposed “no-cost” general emissions factor for the entire state (or preferably by basin) and to figure out how to assign the unreported emissions budget to various facilities. While at a greater cost, basin specific factors maybe more realistic (Denver Julesburg, Piceance, Uinta, San Juan, North Park). Our first pass VOI model is one attempt to demonstrate the value proposition to operators of investing in methane measurement and reduction technologies and practices. The industry would prefer some sort of encouraging carrot (from the market) versus the punishing stick (from regulations).

What would an idea measurement informed methane emissions inventory look like? Of course, practical considerations will necessitate some concessions with an ideal solution, however, we have tried to take a stab at this question by proposing the following attributes of that ideal approach:

- **Integrated, not Reconciled:** Ideally, the measurements at various levels of the digital canopy should be integrated into a holistic quantification of emissions and not subject to the reconciliation of the proposed top-down versus bottom-up scheme currently being proposed. While this reconciliation is the next step it is bound to be hotly contested both by operators arguing their emissions are lower and outside actors arguing that emissions are under-reported. Integration will not be easy challenge to solve as the proposed measurement schemes are very different. One version of the truth will be better than a “dueling data” challenge when explaining to the public if the overall emissions totals (not methane intensity metrics) are being reduced.
- **Flexible:** No two basins, reservoirs, facilities, and equipment processing setups are the same so the scheme must accommodate a broad array of facilities types both from legacy and new production sites and between large (majority) production sites and small (stripper or minority) production sites. How many MEET models will be adequate to represent this diversity? Probably quite a few at this point. Regulations that are not prescriptive are strongly recommended due to these factors and the fast pace of emerging technology developments in methane measurements. But there is opposition from community-based groups for operator self-reporting. This flexibility will place a burden on the state regulatory agencies (as well as operators and third-party service companies) as to how to qualify and verify which technologies and practices will be accepted. Even keeping up with new technology advances and new products and services being introduced in the marketplace will be a challenge or developing a proprietary verification scheme. The role of third-party verification schemes will face a similar challenge.

The role of field inspectors may need to be expanded to add data-inspectors in state staffs. The need to ramp up the data analytics skills of state regulators is inherent. The need for some higher level (federal or industry) to agree to standards (maybe the GTI Veritas protocols or OGMP 2.0 levels or EPA QuadOb and QuadOc) will be very helpful to establish a standard measuring stick to compare against.

- **Multi-purpose:** while in this context, the measurement informed methane emissions inventory is design to improve annual reporting, the major benefit to operators (and ultimately to the community) is in operational response to identifying leaks and fixing them faster and to designing new facilities that design emissions out. Another area of interest is in the forward planning for new CAP (comprehensive area programs) permits. Given studies that suggest the time to meet the COP15 Paris Agreement target of 1.5 degrees C is running out (current pathways are not realistic) there is desire for more dramatic action.

An additional purpose for the operator is in describing the state of their operations to investors (ESG Investing) to allow a more transparent view of potential investment returns (both financial and non-financial). The growing financial concepts of carbon offset trading and certified gas premiums do not impact regulatory reporting but will influence some operator’s actions. It is not the state’s role to ensure

operators make money but driving an industry out of the state with the implications on employment, tax revenue and the like is a draconian outcome.

- **Accuracy:** The most accurate methods will be linked to flow measurements rather than indirect air quality/gas plume measurements (that are influenced by wind speed, direction, and other local environmental conditions). While top-down measurements (satellite and aircraft) are improving rapidly in spatial and temporal resolution, they are still “snapshot” measurements and we know that emissions tend to be intermittent and log-normal distribution (the heavy tail attribute). Continuous monitoring based on operational process control solutions will be the most accurate but potentially the most expensive.

This investment will be considerably less if the operator has already installed a modern instrumentation and process control technology (SCADA) and a time series data management system (historian). The trade-off between accurate measurement and good enough measurements may be one of the toughest decisions an operator and regulator will have to make. A VOI analysis, along with some of the newer modeling tools, will allow operators to make the investment versus value of information decisions themselves.

- **Quantification still involves uncertainty:** From the CSU studies - *“The large variability in performance between continuous monitoring solutions, coupled with highly uncertain detection, detection limit, and quantification results, indicate that the performance of individual continuous monitoring solutions should be well understood before relying on results for internal emissions mitigation programs or regulatory reporting. Additionally, given the rapid development of these solutions, additional implementation standards and regular testing will also be necessary.”* (Bell et al 2022)
- **Predictive:** All stakeholders in this process not only need to understand emissions event when they happen, on an annual basis (or more frequent) for reporting, but also what the emissions will be in the future. So somewhere in this process there needs to be a data-driven, historical inventory based, predictive models (like MEET) so that decisions can be made on meeting future performance targets (both the Colorado state Net-Zero Roadmap, as well as operators own methane reduction plans (like OGCI or the Global Methane Pledge).

But as we can have dueling data, we can have dueling predictive modeling algorithms. Technology can be the enabler for greater insight and better decisions but it can also be a source of confusion and disagreement. Understanding these models require a strong base in statistics and understanding uncertainty which is not a skill many people have.

- **Affordable and Actionable:** The measurement methods need to help the operator, regulator and community recognize the difference between normal operations, false positives, and a significant fugitive event. This is a driver for community health and safety as well as for economic loss and damage, but public health must take priority.

So, the alerts generated by the measurement system should allow the operations and maintenance staff (and in some cases local government response) to quickly identify, locate and quantify events and set in motion the appropriate LDAR processes. New measurement technologies and services will not be free to the operators so understanding the value of new information will help the industry make sound investments and comply with evolving regulations

In conclusion, we want to use an analogy. When you are learning to swim you start out in the shallow end of the pool until your skills and confidence mature. But sooner or later you are going to have to swim in the deeper end. To apply this analogy, all of us are in the shallow end with the use of emissions factors for engineering process and equipment. We have been applying this approach for almost a decade for methane emissions. With new technology developments we are ready to jump into the deeper end to gain a more accurate and timely understanding of methane emissions from upstream oil and gas operations.

But it is still a scary step for those not truly prepared. In Colorado where the industry and the regulatory agencies have been working on this challenge for several years, the inventories are more up to date, the permit and inspections are more routine and the understanding of methane emissions sources are more prevalent. But that does not make it easier to take that step into the deeper end of the pool. It is a step along the journey we all must make, but that does not make it easy.

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Appendix

The Project Canary Pathway Model

<p><u>Cost Benefit Analysis</u></p> $\text{Revenue} = P_{co} \times Q_{co} + P_{ngl} \times Q_{ngl} \times G_p - \frac{Q_w}{C_w} + CC$ $\text{Cost} = OE + MC + CE$ $\pi = \text{Revenue} - \text{Cost}$ $NPV = \frac{(R - C)}{(1 + r)^t}, \quad s. t \ NPV \neq 0$ <p><u>Value of Information Analysis</u></p> <p><i>EVPPI:</i></p> <p><i>Conducted using Monte Carlo simulations if $NPV > 0$.</i></p> $\text{Sensitivity Analysis} = \left(\frac{V2 - V1}{V1} \right) \times 100$	<p>P_{co} = Crude Oil Price Q_{co} = Crude Oil Produced P_{ngl} = NGL Price Q_{ngl} = NGL Produced G_p = RG Premium Q_w = Water Produced C_w = Water Cost CC = Carbon Credits OE = Operating Expense MC = Measurement Cost CE = Capital Expense $V1$ = Actual Cost/Benefit $V2$ = New Cost/Benefit NPV = Net Present Value $EVPPI$ = Expected Value of Perfect Parameter Information</p>
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In the quest to combine environmental responsibility with profitability, the Project Canary Pathway model stands as a unique proposition. This model seeks to reconcile the monetary aspects of oil and gas operations with the pressing requirements of the Methane Rule. It does so by considering multiple revenue streams and costs associated with these operations.

At the heart of the model is the Revenue Function, which calculates the total revenue from oil and gas operations. It incorporates revenues from crude oil and natural gas liquids (NGL) production, water production, and carbon credits obtained from certified operations. Importantly, the revenue from NGL incorporates a premium for responsible gas permission, providing a monetary incentive for operators who voluntarily limit their methane emissions.

The model also provides a detailed cost function, incorporating the operating expense, the cost of emissions measurement conducted by Project Canary, and the capital expense. The inclusion of the cost measure by Project Canary is a key distinction of this model, underscoring the model's commitment to verifiable emissions measurement.

To ascertain the financial viability of operations, the model computes the Net Present Value (NPV). This crucial metric represents the profitability of the project in today's dollars, considering both revenues and costs over a specific time horizon and discount rate. The NPV serves as an indicator of whether the project's benefits exceed its costs, hence informing investment decisions.

Provided the NPV is positive, indicating a beneficial investment, the model proceeds with an Expected Value of Perfect Parameter Information (EVPPI) analysis, utilizing Monte Carlo simulations. The EVPPI is a measure of the value of eliminating uncertainty in the project parameters, providing operators with valuable insights about the potential payoff of investing in additional information.

Finally, to understand the robustness of the model and the impact of changes in key variables, a sensitivity analysis is conducted. The sensitivity analysis measures the percentage change in output due to changes in input variables, providing a quantifiable measure of the model's sensitivity to changes in costs or benefits.

The General Pathway Model

<p><u>Cost Benefit Analysis</u></p> $\text{Revenue} = P_{co} \times Q_{co} + P_{ngl} \times Q_{ngl} - \frac{Q_w}{C_w} + CC$ $\text{Cost} = OE + MF + CE$ $\pi = \text{Revenue} - \text{Cost}$ $NPV = \frac{(R - C)}{(1 + r)^t}, \quad s.t \text{ } NPV \neq 0$ <p><u>Value of Information Analysis</u></p> <p><i>EVPPPI:</i></p> <p><i>Conducted using Monte Carlo simulations if $NPV > 0$.</i></p> $\text{Sensitivity Analysis} = \left(\frac{V2 - V1}{V1} \right) \times 100$	<p>P_{co} = Crude Oil Price Q_{co} = Crude Oil Produced P_{ngl} = NGL Price Q_{ngl} = NGL Produced G_p = RG Premium Q_w = Water Produced C_w = Water Cost CC = Carbon Credits OE = Operating Expense MF = Methane Fee CE = Capital Expense $V1$ = Actual Cost/Benefit $V2$ = New Cost/Benefit NPV = Net Present Value $EVPPPI$ = Expected Value of Perfect Parameter Information</p>
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On the other side of the spectrum, we have the General Pathway model, a comprehensive framework that mirrors the complexity of the methane regulatory landscape. While bearing several similarities to the Project Canary Pathway model, it introduces novel aspects that add layers of depth and distinction to its analysis.

Like its counterpart, the General Pathway model uses a detailed revenue function incorporating revenues from crude oil production, natural gas liquids, water production, and carbon credits obtained from certified operations. However, it lacks the component of responsible gas permission, reflecting a broader focus beyond voluntary methane reductions.

The cost function of this model, like that of the Project Canary model, accounts for operating expenses and capital expenses. A unique feature of this model, however, is the inclusion of a methane fee. This fee is calculated based on the methane intensity of operations, incentivizing operators to decrease their methane emissions and thus comply more effectively with the Methane Rule.

Financial viability is also assessed via the computation of the Net Present Value (NPV). Just as in the Project Canary model, a positive NPV triggers the conduct of an Expected Value of Perfect Parameter Information (EVPPPI) analysis using Monte Carlo simulations. The use of sensitivity analysis to evaluate the impact of changes in costs and benefits is also a common feature between the two models.

Comparison of the Two Models

While both models offer an academically robust framework for understanding the financial implications of the Methane Rule, they do exhibit noteworthy differences.

The Project Canary Pathway model emphasizes a commitment to voluntary methane reductions, as evidenced by the inclusion of the responsible gas permission component in the revenue function. The General Pathway model, on the other hand, directly links emissions to financial costs through its inclusion of the methane fee. This illustrates two different approaches to methane reduction: one incentivizes emissions reduction by offering a premium for responsible practices, while the other penalizes excessive emissions by introducing a fee.

Limitations and Recommendations

Despite their strengths, both models have their limitations. They are based on several assumptions, such as the set value of the operating expense and the premium for responsible gas permission in the Project Canary model, which may not hold true under varying conditions. The models also do not account for potential technological advancements that could drastically alter costs and emissions levels.

To further enhance the models' value, they could be adapted to incorporate more dynamic and variable inputs, reflecting the changing conditions in the oil and gas industry. It would also be beneficial to include a consideration of potential technological advancements that could reduce emissions or improve efficiency.

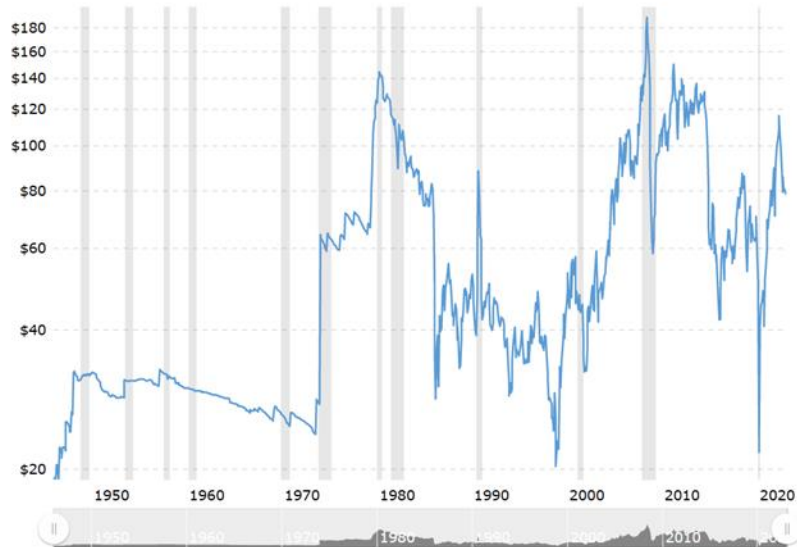
Conclusion

As the industry moves forward in the era of the Methane Rule, the Project Canary Pathway and General Pathway models serve as guiding lights. By offering an academically robust, comprehensive framework for financial analysis, they provide stakeholders with the tools they need to navigate the complex regulatory landscape and work towards more sustainable, profitable operations.

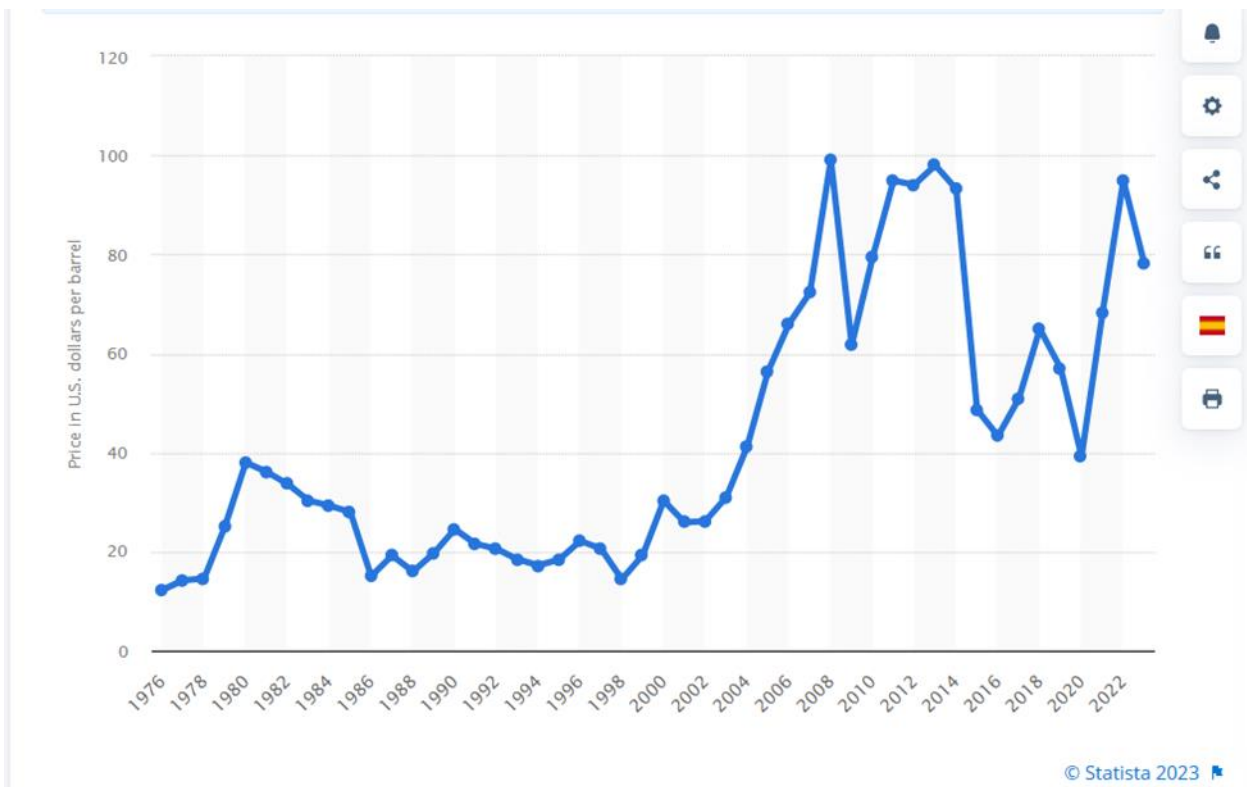
A deeper look at commodity price fluctuations

Crude oil (WTI Crude) = US\$80/BO

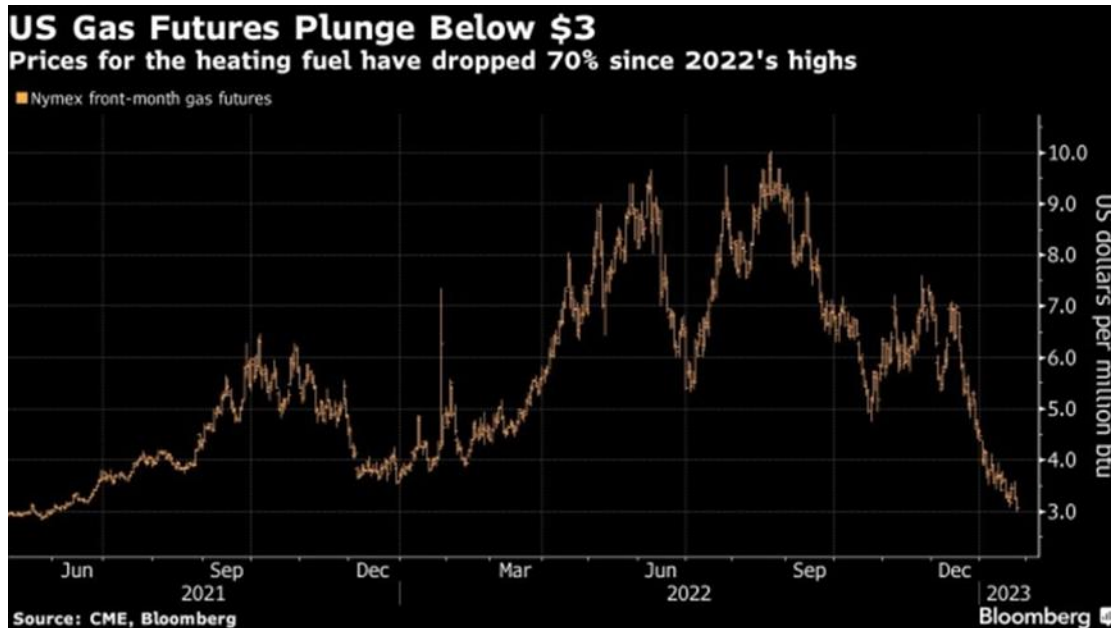
<https://www.macrotrends.net>



Average annual West Texas Intermediate (WTI) crude oil price from 1976 to 2023(in U.S. dollars per barrel)



Natural Gas Henry Hub Spot Price = US\$2.80/ MBTU to \$10.00/ MBTU

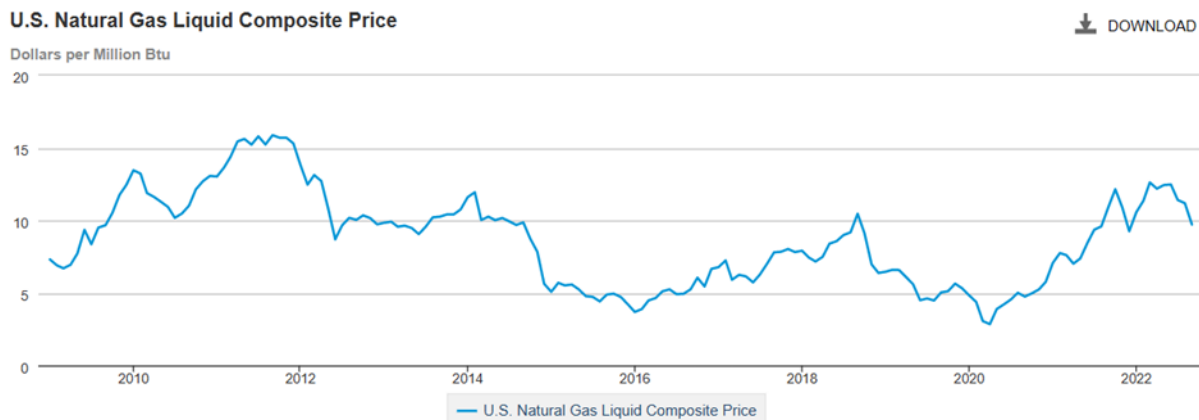


Gas for February delivery lost as much as 8.7% to \$2.80 per million British thermal units Thursday on the New York Mercantile Exchange. Prices have been at the lowest levels since April 2021 after dipping below \$3 on Wednesday.

Doomsday fears that suppliers would not be able to meet wintertime demand have been erased by a confluence of factors, leading gas prices to plunge more than 70% after hitting a 14-year high of \$10.03 in August. The key reason for the fall: The US and Europe managed to refill their buffer inventories ahead of winter, and relatively balmy seasonal temperatures in the Northern Hemisphere have so far damped demand for heating.

The latest revisions to the weather forecast were “absolutely brutal”, indicating that a looming cold shot in the US won’t last much and leading traders to bet on mostly mild February temperatures, said Gary Cunningham, director of market research at risk management firm Tradition Energy. The premium typically commanded for gas delivered in March rather than April — essentially a bet on how tight supplies will be at winter’s end — has reversed to a discount. <https://www.bnnbloomberg.ca/us-natural-gas-falls-below-3-for-first-time-since-may-2021-1.1874933>

Natural Gas Liquids Composite price = US\$9.72/MBTU



<https://www.eia.gov>

Where is the trend in natural gas prices headed?

The Kansas City Fed's quarterly Tenth District Energy Survey gauges current and expected oil and gas activity in the Tenth Federal Reserve District. The district encompasses the western third of Missouri; all of Kansas, Colorado, Nebraska, Oklahoma and Wyoming; and the northern half of New Mexico. Respondents, on average, forecasted Henry Hub prices of \$5.01, \$5.52, \$5.78 and \$6.19/MMBtu for six months, one year, two years and five years from now, respectively. These predictions were down substantially from the third quarter survey, when companies predicted average prices of \$7.46, \$6.48, \$6.16 and \$6.51 for the same time frames.

"Too much supply currently," one respondent said in the latest survey. "Will force prices down and activity down." By 2025, though, increased liquefied natural gas export capacity combined with flat to declining supply "will require higher prices."

The same respondent added, "Drilling and completion costs are continuing to increase while forward commodity prices are decreasing, putting pressure on drilling economics." Asked what natural gas prices were needed for drilling to be profitable across the fields in which they operate, the average response was \$4.32/MMBtu. NGI's Henry Hub Daily Price Snapshot showed an average price of \$2.930 as of Friday. The average price needed to spark a substantial increase in drilling, meanwhile, was \$6.13.

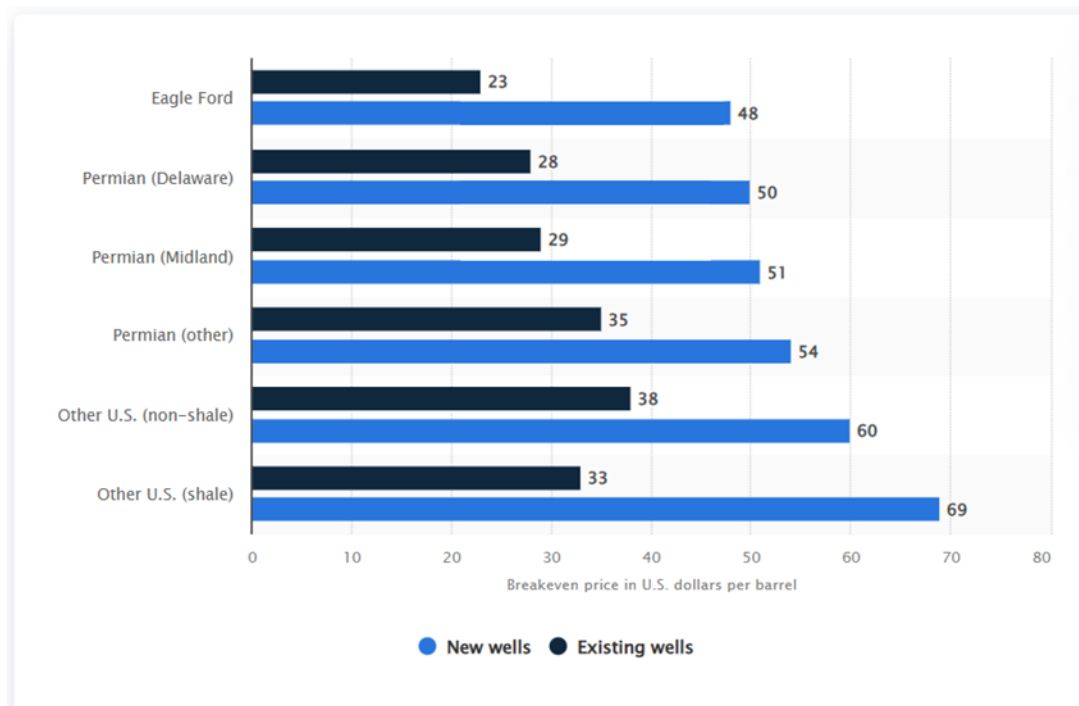
"Inflation pressures are currently high and will need to be arrested before [natural gas production] growth can be resumed or accelerated," one participant said. "There are tremendous price increases tied to increased activity today."

The same respondent predicted that new methane rules proposed by the Environmental Protection Agency "will decimate small producers with older properties if implemented as currently written." Pipeline bottlenecks also are hindering the ability of gas to get where it's needed, said another participant.

Respondents also were asked what the biggest impediment was to oil and natural gas production growth for their firms. Nearly 40% said cost inflation and/or supply chain bottlenecks, while 28% said uncertainty over government regulations. Another 11% said the biggest drag on production was a maturing asset base, while "a handful of firms" cited labor shortages and availability of capital, the authors said.

<https://www.naturalgasintel.com/rockies-midcontinent-producers-slash-natural-gas-price-forecasts-citing-too-much-supply/>

Average WTI price needed for U.S. oil and gas producers to stay profitable by well status in selected U.S. oilfields as of 2022*(in U.S. dollars per barrel)



<https://www.statista.com/statistics/748207/breakeven-prices-for-us-oil-producers-by-oilfield/>

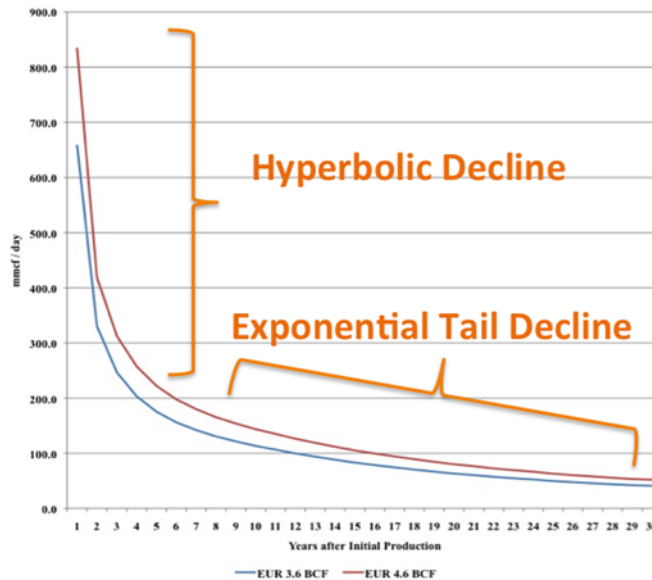
Production Decline Curve

An oil and gas reservoirs are not like a batch manufacturing process where the same number of widgets are produced every year depending on the inputs provided. To better understand reserves estimation, a few important terms require definition. Original oil in place (OOIP) and original gas in place (OGIP) refer to the total volume of hydrocarbon stored in a reservoir prior to production. Reserves or recoverable reserves are the volume of hydrocarbons that can be profitably extracted from a reservoir using existing technology. Resources are reserves plus all other hydrocarbons that may eventually become producible; this includes known oil and gas deposits present that cannot be technologically or economically recovered (OOIP and OGIP) as well as other undiscovered potential reserves.

Estimating hydrocarbon reserves is a complex process that involves integrating geological and engineering data. Depending on the amount and quality of data available, one or more of the following methods may be used to estimate reserves:

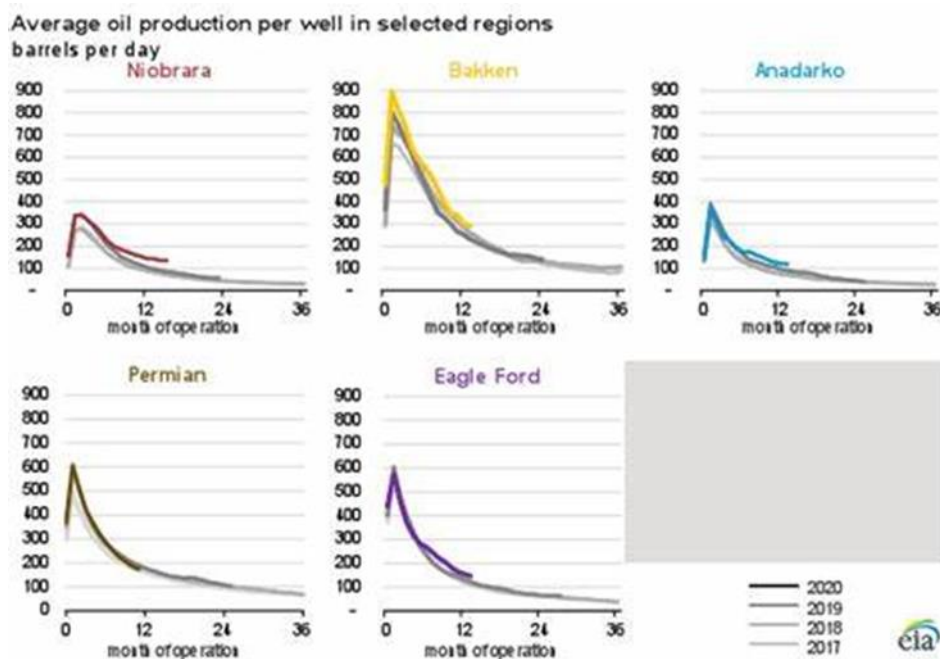
- Volumetric
- Material balance
- Production history
- Analogy

https://wiki.aapg.org/Reserves_estimation

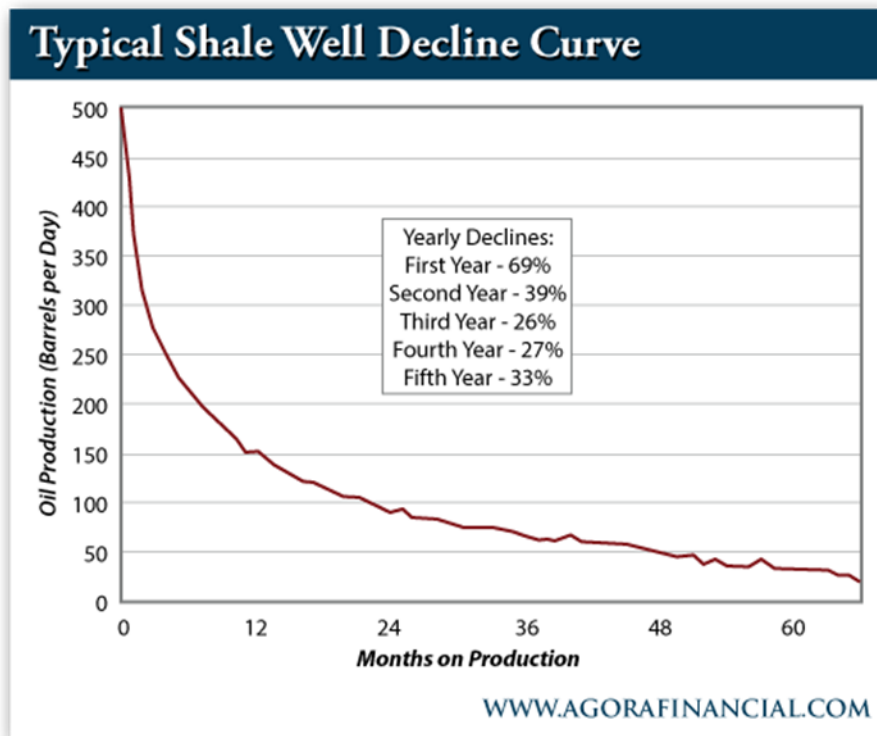


Part of the reason for the rapid emergence of shale gas in the North American natural gas market has to do not only with the sheer number of wells drilled but also the production profile for shale gas wells over time. This production profile is referred to as the decline curve. The production profile of typical shale wells entails a rather sharp initial decline in the production rate and, after a few years, a much slower rate of decline. This becomes very important in determining the profitability of shale gas wells versus conventional gas wells.

<https://www.education.psu.edu/eme801/node/521#:~:text=This%20production%20profile%20is%20referred%20to%20as%20the,of%20shale%20gas%20wells%20versus%20conventional%20gas%20wells.>



<https://www.eia.gov/todayinenergy/detail.php?id=48676>



https://petrowiki.spe.org/Production_forecasting_decline_curve_analysis

Well Economics

According to the consultant BTUAnalytics here are some typical OPEX numbers: “Looking at wells that were drilled and completed between Jan 2014 and Oct 2015 shows significant portions of the region that breakeven below \$35/Bbl wellhead (before transportation and quality adjustments) based on current well \$3.7 MM average well cost.”

Well economics can vary by operator, reservoir, drilling and production strategy, drilling and completions costs, EUR (estimated ultimate recovery) and many other factors. This article from seekingalpha is one such evaluation from 2018.

- Estimate Ultimate Recovery: The expected total amount of barrels of oil equivalent (oil, NGLs, dry gas) recovered over the lifetime of a well - 690,000 BOE for a 6,700-foot lateral well (horizontal reach) - I assume Anadarko is using a 6:1 ratio for dry natural gas (6,000 cubic feet of dry gas equals 1 BOE).
- EUR Composition: 34% crude oil, 34% natural gas liquids (propane, butane, ethane), 32% dry natural gas (methane).
- Total well costs: The expected incremental development cost of turning a well online in the DJ Basin with a 6,700-foot lateral - \$2,700,000 per well (drilling & completion expenses).
- Ongoing production costs (G&A, GP&T, LOE, etc) excluding production taxes (Ad Valorem and Severance): \$10.23 per BOE in 2017 and I assume that climbs to \$10.75 per BOE in perpetuity due to cost re-inflation.
- Production taxes: 5% of gross revenue per well.

- Differentials and realizations: The actual sales price Anadarko receives for its oil & gas sales - \$2.50/barrel below West Texas Intermediate for each barrel of crude sold - \$0.40 below Henry Hub per thousand cubic feet of natural gas sold - Natural gas liquids realizations are assumed to be 50% of WTI - The WTI and Henry Hub pricing benchmarks are held flat at \$65/barrel and \$2.80/Mcf, respectively.

<https://seekingalpha.com/article/4184517-anadarko-petroleum-dj-basin-well-economics>

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Jim retired from Chevron in 2013 after 37 years with the major international oil & gas company. After moving from Houston to Colorado Springs, Colorado, Jim established the Reflections Data Consulting LLC to continue his work in data management and analytics for Exploration and Production industry. Jim was a Distinguished Lecturer for the Society of Petroleum Engineers in 2010-2011 speaking on the topic of "Putting the Focus on Data". He is a frequent speaker at SPE conferences on digital/Intelligent Energy and the Data Foundation. His interests lie in the full spectrum of the information value chain from data capture, data management, data visualization, data access modeling and analytics, simulations, and serious gaming.

Jim graduated from the Colorado School of Mines (BS in Geophysical Engineering in 1974 and MS in Geophysics in 1976) before joining Chevron in Denver, Colorado. He later earned an MBA degree (1976) from Our Lady of the Lake University in San Antonio Texas.

Ebenezer Manful-Sam

MS, Mineral and Energy Economics, Colorado School of Mines

Ebenezer Manful-Sam is a graduate student in Mineral & Energy Economics at the Colorado School of Mines. With an educational background that includes a Masters in Economics, Banking, and Finance from Heriot-Watt University in Scotland, and a BSc in Economics from the Ghana Institute of Management and Public Administration, he brings a unique and diverse perspective to his work.

Presently, Ebenezer is gaining valuable industry experience as an intern at the American Petroleum Institute. Prior to this, he was a Graduate Research Assistant at The Payne Institute for Public Policy and served as a Claims Officer at the National Petroleum Authority in Ghana. His research interests include Carbon Capture Utilisation and Storage (CCUS), Energy Markets, Environmental Policy, Sustainable Energy Finance, and demonstrating his commitment to sustainable energy solutions.

Ebenezer enjoys the stimulation of insightful conversations and the exchange of diverse perspectives and believes in making a difference in his community and the world.

Wyatt Lindsey

MS, Humanitarian Geophysics, Colorado School of Mines

Wyatt Lindsey is currently a graduate student enrolled in the Humanitarian Geophysics 2023 program at the Colorado School of Mines. He obtained a Bachelor's degree in Geology with a minor in Geophysics from Texas A&M University in 2020. Wyatt is interested in the sustainability of the oil and gas industry with a focus on how operations are affected by external forces. For his graduate research, he has learned about stakeholder engagement and how to use qualitative data to coincide with quantitative data for a more encompassing report or research. He believes understanding the challenge, needs, and wants of relevant stakeholders helps generate a better understanding of what is needed from us as geoscientists or engineers, allowing us to think more critically about how to apply geoscience or engineering to better operational practices.

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Pierluigi is a mechanical engineer with an international vocation, speaking six Indo-European languages, additionally learning Arabic and Chinese. He covered lower managerial positions in the energy industry, with a focus on hydrocarbons Exploration and Production, particularly natural gas. He was initiated to the industry by SAIPEM, where he coordinated the redaction of the ENI upstream maintenance standard. His core competencies, way of working and attitude were built mostly at Schlumberger Saudi Arabia, where he worked as in-line manager of well intervention activities serving Saudi Aramco well sites. After he was responsible for O&M of small and medium size PV plants at Greenergy srl. He loves challenges and is trained in managing high risk operations and contingencies promptly and rationally. In all his roles he represented the company in the communication with the customer.

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