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Why Oil Patch Should Be Grateful for EPA Methane Rules

Executive Summary

Because the U.S. Environmental Protection Agency (EPA) systematically underestimates methane emissions from oil and gas drilling and transport activities, the benefits of controlling those emissions also have been underestimated. The EPA has proposed new rules to control methane emissions, and U.S. oil and gas companies have attacked them, claiming they are too costly and of little benefit. But a review by the Institute for Energy Economics and Financial Analysis finds that the EPA's methane control rules could not only have a greater-than-estimated benefit for the climate, but could also generate a greater-than-estimated financial benefit for oil and gas companies.

The oil and gas industry has based many of its critiques on the EPA's inadequate models of methane emissions, which typically show relatively modest levels of methane leaks and venting in the U.S. New research shows the EPA's models are based on outdated assumptions and flawed methods that dramatically underestimate actual emissions by as much as 70 percent. Recent innovations in methane leak detection and data analysis, backed by scientific studies, suggest that methane emissions are far higher than the EPA's outdated models suggest.

Methane has economic value when sold as natural gas. An EPA analysis concluded that the U.S. oil and gas industry could trim its natural gas emissions by 36 million short tons and recoup $4.6 billion from leak reductions over the next 12 years under the new rules. IEEFA's analysis, however, suggests the actual figure will exceed 68 million short tons, resulting in an additional $4.3 billion recovered through future natural gas sales.

Evaluations of the cost effectiveness of leak detection and repair technologies should be based on quantified observations and measurements. The compliance costs of the proposed rules are material. Nevertheless, IEEFA calculates the benefits for oil and gas producers are likely to be much greater than the EPA and industry have predicted because the rules would create increased output—leading to higher margins—and boost proved reserve valuations.

IEEFA's analysis suggests the oil and gas industry margins will be greater—not smaller—if the new EPA methane rules are implemented.

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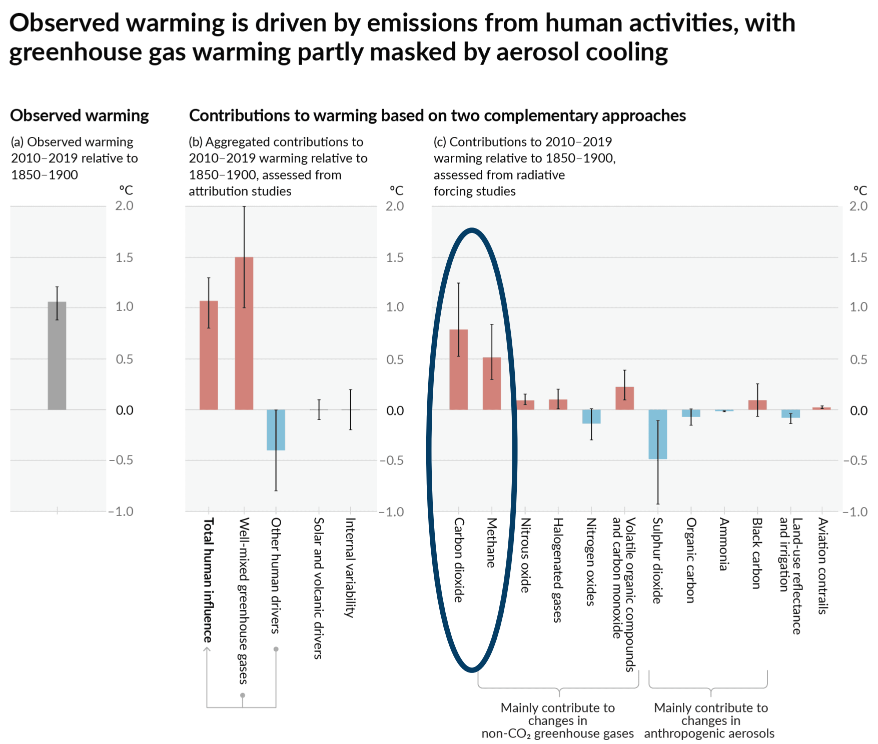
Background

Methane has contributed to 40 percent of the 1.25°C global warming attributed to carbon dioxide and methane since the pre-industrial era (see Figure 1).[1] The EPA estimates methane emissions comprise 11 percent of the nation's total annual greenhouse gas emissions.[2] The U.S. produces roughly 23 percent of the world's natural gas,[3] clearly indicating it is responsible for an outsized share of total global methane emissions.[4]

Figure 1: Carbon Dioxide and Methane Are Major Drivers of Global Warming



Source: IPCC.

[1] Methane, the main component of natural gas, is an important target for climate action because it has 80 to 86 times greater warming potential than CO_2 over the first 20 years after it is released into the atmosphere. See: Intergovernmental Panel on Climate Change (IPCC). Climate Change 2021. The Physical Science Basis. Contribution of Working Group 1 to the Sixth Assessment Report of the IPCC. 2021. Also see: IPCC. Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report. 2014, p. 87. Also see: IPCC. Climate Change 2013: The Physical Science Basis. Chapter 8: Anthropogenic and natural radiative forcing. 2013.

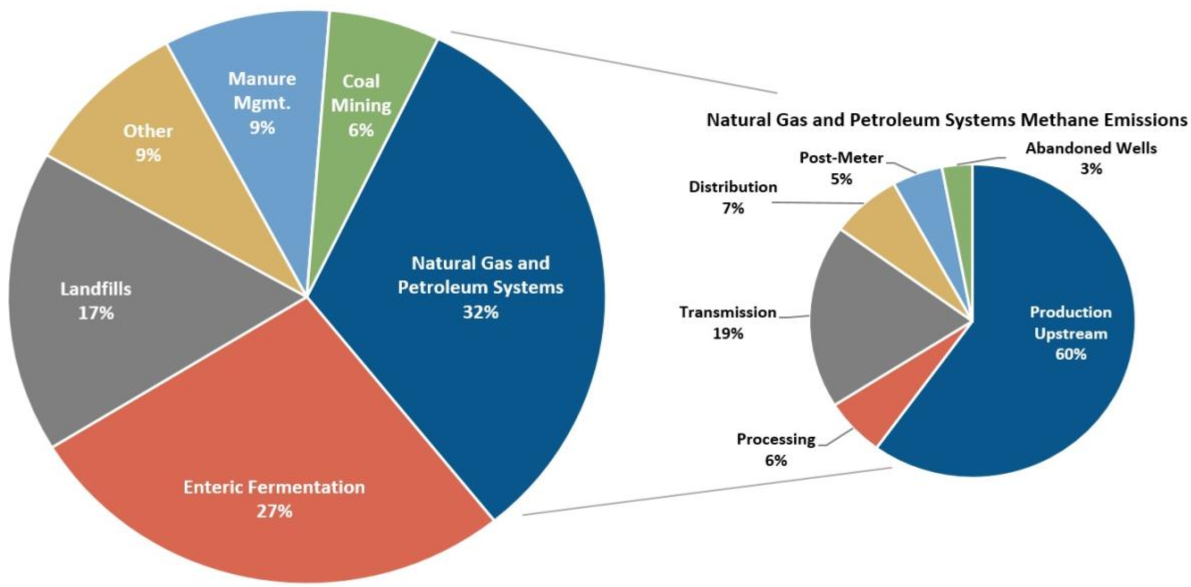
[2] EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020. p 2-3, Table 2-1.

[3] bp. Statistical Review of World Energy 2022. June 2022. The percentage is based on 2021 data.

[4] Besides human activities such as fossil fuel extraction, landfills, wastewater treatment, and raising livestock, methane occurs naturally from sources such as wetlands, oceans, termites, and volcanoes. Congressional Research Services. Methane Emissions: A Primer. March 16,2022.

The EPA identifies natural gas and petroleum production as the largest industrial source of methane in the U.S., responsible for 32 percent of the country's methane emissions. Upstream activities—exploration and production of hydrocarbons—are responsible for roughly three-fifths of the total.[5] (See Figure 2.)

Figure 2: 2020 U.S. Methane Emissions, By Source



Source: EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020 (2022).

The most recent EPA effort to curb methane emissions is strongly supported by the Biden administration,[6] and is a clear reversal from how policy was being shaped during the prior administration. The Clean Air Act authorizes the EPA to establish New Source Performance Standards (NSPS) for stationary sources that significantly contribute to air pollution levels of certain contaminants anticipated to endanger public health. The oil and natural gas sector is a specific category within the EPA's definition of regulated stationary sources.[7] In 2016, the EPA issued a rule directly regulating methane emissions from onshore oil and natural gas production sources that began construction, modification or reconstruction after Sept. 15, 2015. The facilities subject to the rule include oil and natural gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, and storage vessels.[8]

A Trump administration rule adopted in 2020 removed methane from the list of regulated pollutants and eliminated transportation and storage segments from the

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[5] United States Environmental Protection Agency (EPA). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020.
[6] White House. Fact Sheet: President-elect Biden's Day One Executive Actions Deliver Relief for Families Across America Amid Converging Crises. January 20, 2021.
[7] EPA. Industry Sector Groups. Website accessed October 4, 2022.
[8] Federal Register. Oil and Natural Gas Sector: New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants Review. See 40 C.F.R Part 60 Subpart OOOO. August 16, 2012.

rule.[9] Congress and President Biden, however, used the Congressional Review Act in June 2021 to restore methane regulations.[10]

In November 2021, the EPA proposed an NSPS rule that would apply tougher requirements for methane emissions from new sources. The text of the proposed rule listed a summary of 23 affected sources, a best system of emission reduction (BSER), and standards of performance. The EPA also created methane emissions guidelines for states to use in developing their own regulations to address existing methane emission sources.[11]

Highlights of the proposal include:

- Changes to the regulatory threshold capacity for storage tanks, making an entire battery of tanks subject to the 6-ton-per-year limit that previously applied to each individual tank. The change would require more storage vessels to comply and report emissions than before.
- Sets stricter monitoring schedules for leak detection and repair (LDAR) across a spectrum of sources.
- Prohibits flaring (essentially, uncontrolled burning) of associated gas if the gas can be diverted into a pipeline for transport and marketing.
- Applies reduced emission completion (REC) guidelines, a practice that reduces flaring, to well completion operations with hydraulic fracturing.
- Establishes a zero-emission limit for unloading operations of well liquids.

In November 2022, the EPA released a supplemental proposal that sought to reflect the numerous comments and input on the earlier proposal. After another comment period, the EPA expects to issue its final rule in 2023. Comments are due on or before Feb. 13, 2023.[12] Key changes from the supplemental proposal include:

- Inclusion of wellhead-only well sites to ensure monitoring of all well sites for fugitive emissions.

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[9] Congressional Research Services. Looking Ahead: Regulating Methane from the Oil and Natural Gas Sector. July 14, 2021.

[10] The Congressional Review Act did not address the Trump administration's 2020 Technical Rule that exempted operators producing less than 15 barrels of oil equivalents per day from the regulation. Leak detection and repair requirements for VOC emissions do not apply to such low production well sites, under the 2020 Technical Rule. Yet, the Congressional Review Act passage places these wells back under NSPS 2016, which subjects them to semi-annual methane LDAR requirements. So, discrepancies between VOC standards and methane standards now exist for these well sites.

[11] Federal Register. 86 FR 63110. November 15, 2021. The EPA anticipates it will take states about three years to implement the guidelines for existing methane emission sources once the rules are adopted. *Ibid.*

[12] EPA. EPA Issues Supplemental Proposal to Reduce Methane and Other Harmful Pollution from Oil and Natural Gas Operations. November 11, 2022.

- Bases requirements for the type and frequency of monitoring on the amount and kind of equipment at the site, rather than on estimated emissions as the 2021 proposal had provided.
- Subjects control devices to continuous monitoring and regular inspections.
- Requires operators conducting optical gas imaging monitoring to follow procedures in NSPS regulatory text or EPA Method 21.
- Appendix K would apply to optical gas imaging surveys used to detect leaks at onshore natural gas plants rather than only if a rule specified its application.
- Requires monitoring of all well sites over the life of the well (even if idle) until it is properly plugged and a final monitoring survey using optical gas imaging shows no emissions.
- Allows use of a broader range of technologies as alternatives to optical gas imaging or EPA Method 21.
- Creates a super-emitter response program to identify large leaks for mitigation.
- Requires operators to route associated gas to a sales line, use the gas for fuel or other beneficial purposes, or reinject it into a well for enhanced oil recovery to limit flaring for eliminating venting or associated gas from oil wells.
- Sets additional compliance requirements for flares. Requires immediate corrective action if a flare is having a super-emitter event. EPA is proposing to define a super-emitting event as emissions of 100 kilograms (220.5 pounds) of methane per hour or larger.
- Sets a zero-emission standard for all pneumatic pump-affected facilities except at sites that do not have access to electricity.
- Updates definition of affected facility for pneumatic controllers—a collection of all natural gas controllers at a well site, centralized production facility, onshore natural gas processing plant, or compressor station.
- The EPA is proposing a presumptive standard of zero methane emissions for liquids unloading at existing wells.
- Sets standards for dry seal compressors that were not previously regulated.

- Clarifies and details requirements for states to develop emissions reductions plans for existing sources, to be submitted to the EPA 18 months after final emissions guidelines are published in Federal Register.[13]

Oil and gas industry representatives have argued that the costs of compliance will be prohibitive for smaller producers, and that the costs of replacing gas controllers with non-emitting pneumatic controllers in existing sources also will be prohibitive.[14]

The EPA's regulatory impact analysis relies significantly on the agency's model for estimating greenhouse gas intensity (GHGI).[15] In recent years, strong evidence has grown that shows the EPA's model underrepresents methane emissions from oil and gas industry operations. This report explores the impact of that underrepresentation on the regulatory impact analysis and the cost-benefit calculation that the oil and gas industry (and the EPA) should be conducting.

I. EPA Underestimates Methane Emissions From Oil and Gas Operations

The industry argument regarding the cost-effectiveness of leak detection and repair technologies needs to be reevaluated with better data than the EPA's Inventory of Greenhouse Gas Sources and Sinks. The EPA estimates of methane emissions from across the U.S. oil and gas industry's operations are overly conservative due to an overall lack of monitoring and the inaccuracy of the EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990 – 2020.[16] Numerous studies have demonstrated that the EPA underestimates methane emissions in the oil and gas sector.[17]

A 2021 Stanford University study found that the EPA's GHGI model for estimating and reporting emissions falls well short of identifying methane emissions levels consistent with observations in the field. The researchers followed the approach

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[13] EPA. Supplemental Notice of Proposed Rulemaking: Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. November 11, 2022.
[14] See, *e.g.*, Texas Oil and Gas Association, Comments on Standard of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. January 31, 2022. p. 20.
[15] EPA. Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. November 11, 2022 (updated).
[16] EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020.
[17] Alvarez *et al*. Assessment of methane emissions from the U.S. oil and gas supply chain. Science, 361(6398). 2018, pp 186–188. Also see: Chen et al. Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey. Environmental Sci. & Tech. 56 (7). 2022, pp 4317-23. Also see: Omara *et al*. Methane emissions from natural gas production sites in the United States: Data synthesis and national estimate. Environmental Sci. & Tech. *52*. 2018, pp 12915– 25. Also see: Michanowicz *et al*. Methane and Health-Damaging Air Pollutants from the Oil and Gas Sector: Bridging 10 Years of Scientific Understanding. October 6, 2021, Table 3.1, p 3-5.

used by the EPA—called a "bottom-up" estimate, since it gauges emissions based on estimated leakage rates for individual activities or pieces of equipment—to understand why the EPA model understated emissions. Their conclusions for leak rates were very similar to a 2018 study published in the journal *Science*.[18] The Stanford researchers concluded that unintentional leaks were responsible for almost half of all methane emissions in the oil and gas sector.[19]

Because they followed much of the modeling methodology used by the EPA, they were able to rule out the bottom-up approach as the reason for variances. Instead, the Stanford researchers found that the EPA's component-level data was outdated. "If our emissions-based models that we use to make important climate-related decisions are not correct, it is a big problem," said Adam Brandt, Stanford's Natural Gas Initiative Director.[20]

Similarly, the House Committee on Science, Space and Technology conducted interviews over an 18-month span, probing emission reduction strategies for 10 Permian Basin operators. The evidence obtained by the committee gathered in 2022 confirmed that the oil and gas sector relies on poorly designed and outdated models to measure methane emissions instead of using direct observations.[21]

The House committee concluded that "oil and gas companies are failing to design, equip, and inform their Methane Leak Detection and Repair (LDAR) activities as necessary to achieve rapid and large-scale reductions in methane emissions from their operations."[22]

Since methane is a valuable commodity, prevalent leak understatements would result in an under-weighing of the benefits of deploying leak remediation solutions. An overly conservative evaluation of benefits implies that the thresholds for associated acceptable expense levels are also set too low. The likely outcome of these conditions is that fewer projects for methane emission reductions get the green light than would be the case if a better representation of benefits from implementation were known.

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[18] Alvarez et al, *op. cit.*, pp 186–188.
[19] Rutherford et al. Closing the methane gap in US oil and natural gas production emissions inventories. Nature Communications 12,4715 (2021).
[20] Stanford Earth Matters Magazine. A better way to track methane in the skies? August 9, 2021.
[21] House Committee on Science, Space and Technology. Staff Report – Seeing CH4 Clearly: Science-Based Approaches to Methane Monitoring in the Oil and Gas Sector. June 2022.
[22] House Committee on Science, Space and Technology. Staff Report – Seeing CH4 Clearly: Science-Based Approaches to Methane Monitoring in the Oil and Gas Sector. June 2022.

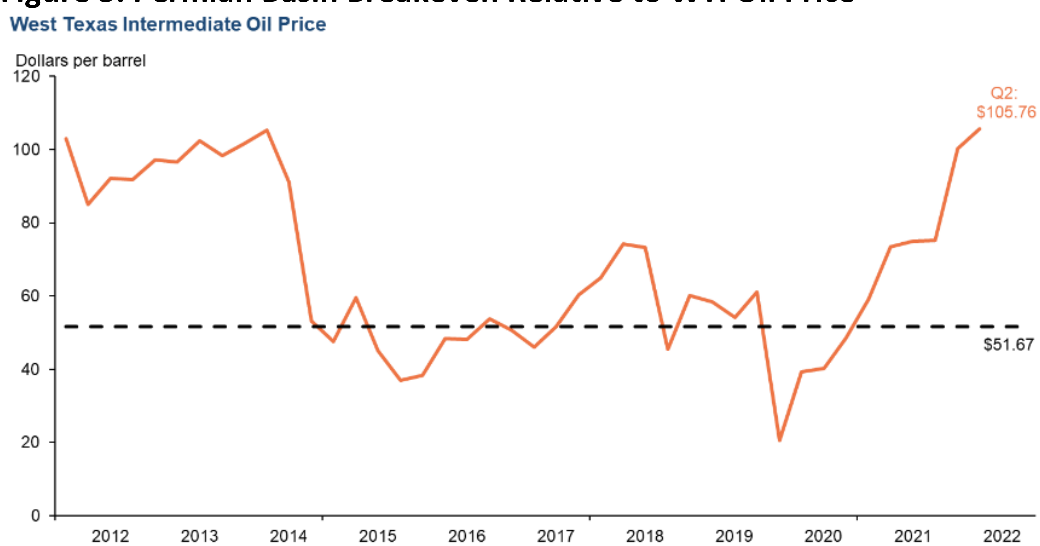
II. Incorrect Quantification of Methane Emissions Impairs the Calculation of an Oil or Gas Company's Proved Reserves (PV10)

Proved reserves are projections of a firm's future production volumes by the type of extracted hydrocarbon (i.e., oil, natural gas and natural gas liquids). They include the estimated volumes of hydrocarbons that geologic and engineering data analyses consider reasonably certain to recover under existing economic and operating conditions. Proved reserves are not a measure of how much hydrocarbon is in the ground; they measure the amount that a producer can afford to extract at a given price.

Proved reserve estimates vary over time, primarily due to changes in ownership, new discoveries, reappraisals of existing fields, changes in technology and the depletion of existing reserves. Also, changes in prices of the underlying commodities or the costs of production can result in adjustments to the volume of proved reserves.

For example, surveys by the Dallas Federal Reserve indicate that new exploration in the Permian Basin requires oil prices to exceed $51 per barrel to recover well development costs.[23] If oil prices drop below $51 per barrel, then some portion of future production is no longer economically accessible and no longer included in proved reserve calculations for a Permian Basin producer.

Figure 3: Permian Basin Breakeven Relative to WTI Oil Price



NOTE: The dashed line indicates the mean price needed to profitably drill a new well in the Permian Basin (averaging the Delaware, Midland and other regions), according to the first quarter 2022 Dallas Fed Energy Survey.The orange line is the West Texas Intermediate price for the first expiring contract settlement.
SOURCE: Chicago Mercantile Exchange; Dallas Fed.

Source: Dallas Federal Reserve.

[23] Federal Reserve Bank of Dallas. Permian Basin Economic Indicators. August 12, 2022.

Annual reports filed with the Securities and Exchange Commission (SEC) by oil and gas producers share a similar format for presenting economic valuations of proved reserves. When proved reserves are multiplied by the prevailing underlying commodity prices, the product represents future cash inflows to a company. Since the production from proved reserves occurs over several years, the future cash inflows must be discounted to their present value. The discount rate used to return amounts to present value is mandated by the SEC at 10 percent for corporate filings, explaining why the calculation for valuing a company's proved reserves is called a PV10.

SEC rules for PV10 reporting were designed to ensure the valuations of reserves were comparable among companies. Prices of the underlying hydrocarbons to be extracted are another standardized feature of the PV10. Expected future net cash inflows are computed by multiplying the proved reserves by their respective commodity prices, using an unweighted average of oil, natural gas and natural gas liquids prices in effect on the first day of each month in the preceding 12 months of the fiscal year when no contract for sale of future production determines future prices.

As a further standardization method, the operation, production, taxes and future development costs (based on current costs with no escalation) are summarized within the categories Production Cost, Development Cost, and Income Tax Expense when presented with future cash inflows in the company's annual 10-K filing. The three summary categories are subtracted from cash inflows to arrive at the net cash flows. Net cash flows are then reduced by the 10 percent discount factor, with the result being the standardized measure of discounted future net cash flows.

As an example, Figure 4 presents excerpts from Pioneer Natural Resources' 2021 10-K footnotes that illustrate how typical formats for proved reserves, reserve prices, and PV10 calculations are presented.

Figure 4: Proved Reserves Footnote Tables From Pioneer Natural Resources

The following table provides a rollforward of total proved reserves. Oil and NGL volumes are expressed in MBbls, gas volumes are expressed in MMcf and total volumes are expressed in MBOE.

	Year Ended December 31,											
	2021				2020				2019			
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)
Total Proved Reserves:												
Balance, January 1	568,784	379,187	1,940,100	1,271,321	603,750	281,983	1,499,513	1,135,652	565,010	240,914	1,458,574	1,049,020
Production (b)	(130,300)	(52,204)	(272,351)	(227,896)	(77,095)	(31,376)	(166,863)	(136,282)	(77,509)	(26,398)	(145,026)	(128,078)
Revisions of previous estimates	(65,884)	242	161,822	(38,672)	(68,300)	73,107	342,720	61,927	(30,216)	29,415	94,767	14,994
Extensions and discoveries	230,458	136,716	688,637	481,947	111,239	55,952	267,497	211,774	167,022	60,069	293,507	276,009
Sales of minerals-in-place	(113,898)	(33,566)	(143,669)	(171,409)	(1,480)	(803)	(4,434)	(3,022)	(20,603)	(22,032)	(202,401)	(76,369)
Purchases of minerals-in-place	478,468	239,605	1,132,169	906,768	670	324	1,667	1,272	46	15	92	76
Balance, December 31	967,628	669,980	3,506,708	2,222,059	568,784	379,187	1,940,100	1,271,321	603,750	281,983	1,499,513	1,135,652

The NYMEX prices used for oil and gas reserve preparation, based upon SEC guidelines, were as follows:

	Year Ended December 31,			
	2021	2020	2019	2018
Oil per Bbl	$ 66.56	$ 39.57	$ 55.93	$ 65.57
Gas per Mcf	$ 3.60	$ 1.98	$ 2.58	$ 3.10

The standardized measure of discounted future cash flows as well as a rollforward in total for each respective year are as follows:

	December 31,		
	2021	2020	2019
		(in millions)	
Oil and gas producing activities:			
Future cash inflows	$ 95,717	$ 30,357	$ 40,902
Future production costs	(29,682)	(14,784)	(19,687)
Future development costs (a)	(2,621)	(1,124)	(1,858)
Future income tax expense	(4,584)	(494)	(1,096)
Standardized measure of future cash flows	58,830	13,955	18,261
Ten percent annual discount factor	(31,146)	(6,753)	(8,527)
Standardized measure of discounted future cash flows	$ 27,684	$ 7,202	$ 9,734

(a) Includes $801 million, $595 million and $584 million of undiscounted future asset retirement expenditures estimated as of December 31, 2021, 2021, 2020 and 2019, respectively, using current estimates of future abandonment costs at the end of each year. See Note 9 for additional information.

Source: Pioneer Natural Resources 2021 10-K.

The valuations of oil and gas producers rely on two cash flow components reported by all producers: The current cash flow stream and the future cash flow stream. Although an oversimplification, both streams are calculated using their respective production volumes multiplied by a selling price per unit of production, less the costs of production and other expenses.

From items reported in the footnotes to publicly-traded producers' annual reports, one can derive the natural gas component of net future cash flows and how capturing differing rates of methane emissions from natural gas and petroleum production systems would increase valuations.

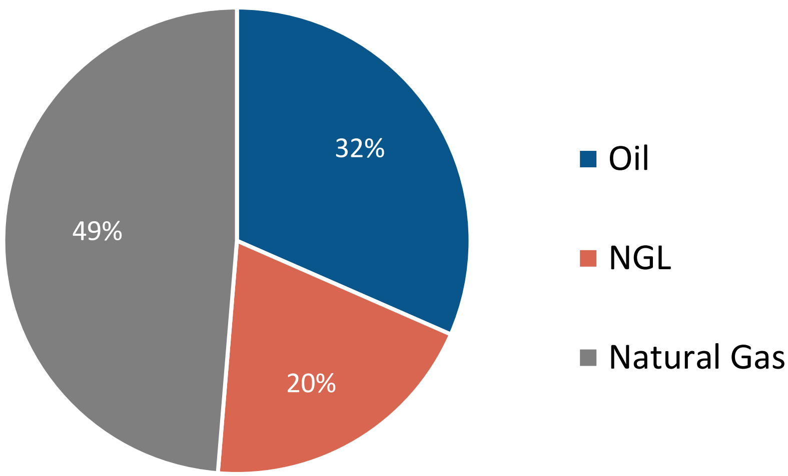
IEEFA reviewed the footnote presentations for proved reserves valuations of 38 publicly traded oil and gas producers.[24] The 38 companies were responsible for one-

[24] Annual Reports (10-K) filed with the Securities and Exchange Commission by: Antero Resources, APA Corp. (was Apache Corp.), Berry, Civitas (previously Bonanza Creek Energy), Coterra (Previously Cabot and Cimarex), California Resources, Callon Petroleum, Permian

third of U.S. natural gas production in 2020. All 38 companies were also constituents of the SPDR S&P Oil & Gas Exploration & Production Exchange Traded Fund (ETF), which is a proxy index for U.S. upstream stock market returns. We will refer to this exchange traded fund by its ticker symbol "XOP" and the observed companies as the XOP group.

Almost half of XOP group's proved reserves are natural gas, representing 27.7 billion barrels of oil equivalents, or more than one-third of total U.S. natural gas proved reserves, which are currently estimated at 77.6 billion barrels of oil equivalents. This large representation by just 38 companies reinforces our opinion that the XOP group is a good proxy for the U.S. upstream oil and gas industry.

Figure 5: Proved Reserve Composition for XOP Group by Hydrocarbon



Source: Company Reports.

For our observed group, the amount of projected natural gas available for future sale, as disclosed in the 10-K reports,[25] is 50.4 percent of the amount of gross gas extracted from the reservoir based on the self-reported data gathered by the EPA in its Greenhouse Gas Reporting Program (GHGRP),[26] under existing production

Resource, Chevron, CNX Resources, Comstock Resources, ConocoPhillips, Contango Resources, Continental Resources, Devon Energy, Diamondback Energy, EOG Resources, EQT, ExxonMobil, Gulfport Energy, Hess, Laredo Petroleum, Magnolia Oil & Gas, Marathon Oil, Matador Resources, Murphy Oil, Northern Colorado Oil & Gas, Chord (previously Oasis Petroleum and Whiting Petroleum, Occidental, Ovintiv, PDC Energy, Ranger Oil (previously Penn Virginia), Pioneer Natural Resources (acquired Parsley), Range Resources, SM Energy, and Southwestern Energy for Fiscal Year 2020.

[25] *Ibid*.

[26] U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program (GHGRP): 2020 Data Summary Spreadsheets (zip). Accessed August 15, 2022. Also see: ERM. Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production In the United States. July 2022. Both methane emissions and gross natural gas production per operator are self-reported pieces of data that are available to the public through the GHGRP, annually.

patterns. The GHGRP reporting requirements apply to petroleum and natural gas facilities that annually emit more than 25,000 metric tons of CO_2 equivalent (CO_2e).

The ratio of marketed production to gross production for the XOP group is not unusual for the industry. The differences between gross and marketed production figures result from natural gas usage at the production site; the number of processes designed to vent and flare gas; the loss of nonhydrocarbon gases removed from the gas stream; the extraction of condensates and natural gas liquids (NGLs);[27] and unintentional emissions.

The magnitude of difference between gross and marketed natural gas production is important because leak estimates reported to the GHGRP are relative to gross production. Conversely, reserve estimates reported to the SEC are estimates of future marketed production.

To understand the relationship between the percentage of a company's methane emissions and its proved reserves, we must convert the GHGRP percentage of leaks from gross production to its appropriate weighting for marketed production. A company's percentage of methane emissions from upstream production must be multiplied by its ratio of gross production to marketed production volumes to arrive at the leaked volume percentage that is not available for sale in proportion to its proved reserves estimate.

The extrapolated percentage when multiplied by natural gas proved reserves is the implied amount of extracted proved reserves lost during production due to leaks and unreported in financial statements.

The amounts of lost cash inflows are significant in size and hold economic value for the industry, because markets for the leaked natural gas would have been readily available for its sale.

III. Analysis – Plugging Leaks Leads to Higher Valuations

IEEFA's analysis of the impact of plugging methane leaks is based on the following initial assumptions:

- The largest component of natural gas is methane.
- Methane emissions throughout the entire oil and natural gas supply chain equal 1.5% of gross natural gas production.[28]

[27] U.S. Energy Information Administration. Definitions, Sources, and Explanatory Notes. Accessed September 3, 2022.
[28] United States Environmental Protection Agency (EPA). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020.

- Methane emissions from upstream oil and gas production are 60% of natural gas and petroleum production systems, based on the EPA's inventory from 1990 to 2020.[29]

- Multiplying the EPA's industry leak rate of 1.5% by the 60% proportion leaked upstream yields a leak rate for upstream methane emissions of 0.9% from gross natural gas production.

- Dividing the upstream methane emissions leak rate, 0.9%, by the ratio of marketed-to-gross production, 50.4%, yields a marketed production leak rate of 1.7% that applies to upstream producers' proved reserves.

- The 1.7% leak rate multiplied by 80% (an estimate to adjust for methane's composition in the natural gas stream), yields a net upstream leak rate of 1.4% of marketed natural gas production, based on EPA emissions estimates.

- Assumed emission reductions from the use of optical gas imaging are dependent on the frequency of monitoring. IEEFA estimates 45% reductions from annual monitoring, 67% reductions from semiannual monitoring, 77% reductions from quarterly monitoring, 81% reductions from bi-monthly monitoring, and 85% reductions achieved from monthly monitoring.

IEEFA extrapolated natural gas PV10 valuations for each member of the XOP group using data from their total proved reserve valuations in 2021 annual reports. IEEFA then computed the additional reserves lost to leakage and calculated pro forma PV10s for natural gas reserves that incorporated the additional volumes of natural gas recaptured.

A sensitivity analysis was generated to observe how various assumptions for emissions rates affected valuations. Besides the methane emission percentages reported in the GHGI, IEEFA applied methane leak rates from a Stanford study and a third study from Cornell University in the sensitivity analysis.[30],[31] The emission rates as a percentage of gross natural gas production were 1.5%, 2.3%, and 3.2%, respectively, across the entire oil and natural gas systems. IEEFA recomputed these estimates to represent the percentage of emissions from just upstream marketed production. These leak rates as a proportion of marketed production were calculated as 1.4%, 2.2%, and 3.0%, respectively.[32]

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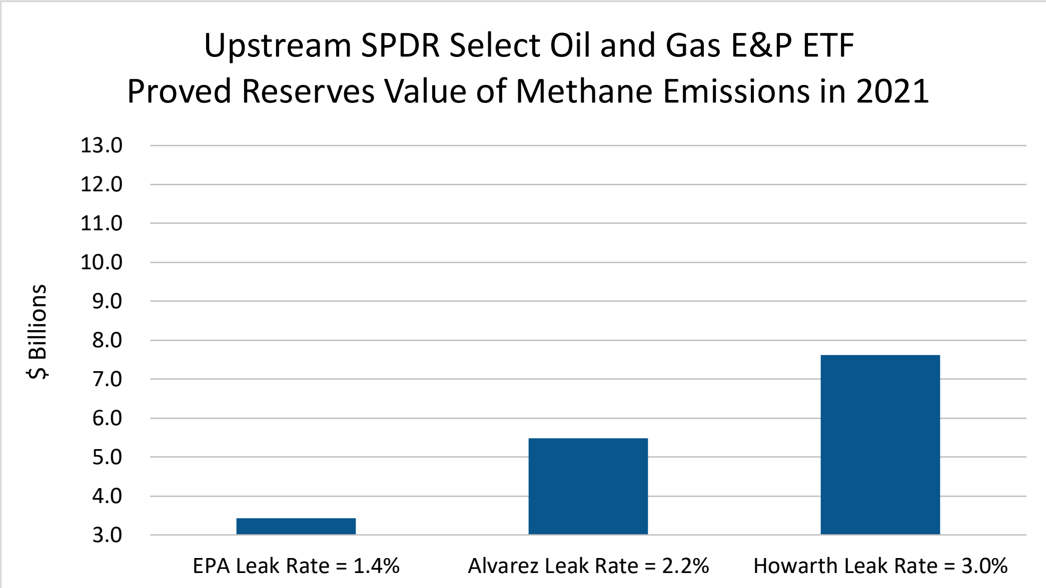
[29] *Ibid*.
[30] Alvarez et al. Assessment of methane emissions from the U.S. oil and gas supply chain. Science, 361(6398), pp 186–188.
[31] R. Howarth. Methane and Climate Change. 2021. The upstream emission estimate taken from this study is the estimated threshold point at which methane leaks from natural gas production create a greater greenhouse gas impact than coal when both are combusted for electric power generation.
[32] Marketed natural gas emission percentage computed from the EPA's 1.5% emissions from gross production multiplied by 59.7% upstream production methane emissions proportion of supply chain divided by the net marketed to gross production ratio for the XOP group of 50.4% and then multiplied by 80% composition of methane in natural gas. Similar calculations were

Figure 6: Unvalued Proved Reserves Due to Methane Leaks



Source: Company reports, IEEFA projections.

The three scenarios used an extrapolated PV10 starting valuation for the XOP group's natural gas proved reserves of $140.6 billion with production volumes of 45 billion cubic feet (bcf) per day for the next 10 years. Across these three scenarios, IEEFA found the value of proved reserves could improve by a range of $3.4 billion to $7.6 billion, depending on leakage assumptions. On a percentage of estimated natural gas proved reserves reported for 2021, valuation improvements from capturing leaked gases would range from between 2.4% to 5.4% above the reported proved reserve valuations.

IEEFA compared estimates for methane emissions from proved reserves between the EPA calculation and Stanford calculation assumptions, using EPA calculations as the base case and assuming the Stanford calculations are a realistic yet conservative assessment of nationwide average of leak rates for upstream production.[33]

The $2.05 billion difference between Stanford and EPA's proved reserves additions from stopping all leaks illustrates how the use of EPA's reporting leads to an understated valuation for each company's methane emissions within the XOP group. Since the XOP group's proportion of natural gas proved reserves is one-third, the entire industry's natural gas proved reserves may be understated in value by as much as $6.2 billion.

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used for the Stanford and Cornell studies, except starting percentages for emissions from gross production were 2.3% and 3.2%, respectively.

[33] Zhang *et al*. Quantifying methane emissions from the largest oil-producing basin in the United States from space. *Science Advances*. Volume 6 Issue 17. April 2020. Table S-1 identifies 11 aircraft-based studies for various basins in the U.S. with their emission rates, along with the study's estimate of 3.7% for the Permian Basin's methane emissions.

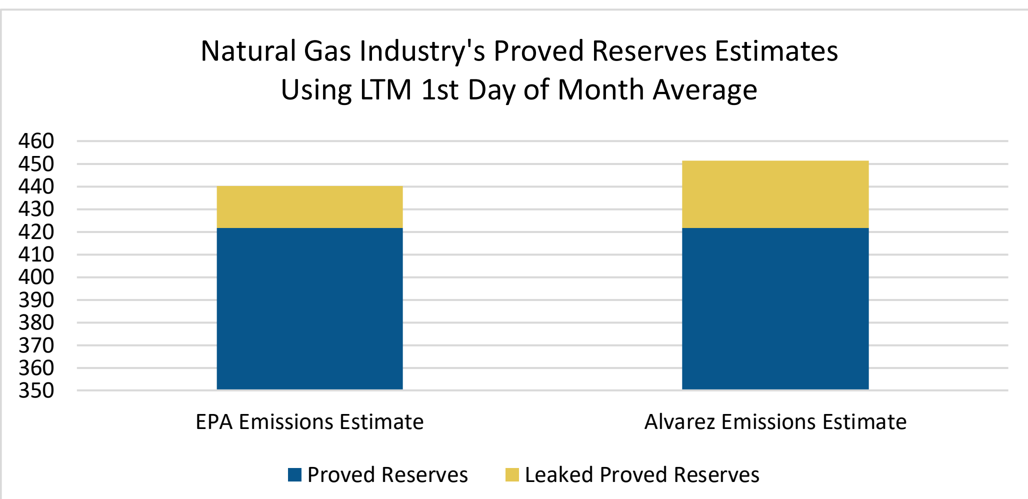
It's also possible to calculate the benefits that the industry loses from the leaks on a dollars-per-metric ton scale. Given that the upstream industry reported 5.4 million metric tons (~134 MMT CO_2e divided by 25x Global Warming Potential) of methane emissions in 2019, the industry could be ignoring as much as a $1,151 ($6.2 billion divided by 5.4 MMT) in benefits per ton from capturing methane emissions.

The calculations are based on 2021 natural gas prices that were much lower than today's spot market prices. Natural gas prices used in the 2021 proved reserve calculations averaged $3.45 per million British thermal units (MMBtu) for the 38 companies we observed in the XOP group. Over the last 12 months (LTM), however, the average unweighted price for natural gas on the first day of the month was $6.25 per MMBtu, 81% higher than the average price used in 2021 PV10 calculations.

Methane leaks are costing the industry between $19 billion and $42 billion in proved reserves valuations after adjusting for natural gas prices over the last 12 months. A comparison between leak rates from the EPA's GHGI and from the Stanford study identifies a variance of $11 billion or $2,092 per metric ton overlooked by the industry. (See Figure 7.) To put this oversight into context, the industry is ignoring a valuation benefit that is far greater per metric ton than the emissions charge for methane under the Inflation Reduction Act of 2022.[34]

Currently, the price of Henry Hub natural gas is around $7 per MMBtu, two times more than the price used in the original sensitivity analysis valuations on proved reserves, and $0.57 higher than the revised LTM average price presented. In this light, the benefits from stopping leaks are likely far greater than our analysis.

Figure 7: Industry-wide Unvalued Proved Reserves Due to Methane Leaks



Source: EIA, IEEFA projections.

[34] The methane emissions charge applies to facilities required to report greenhouse gas emissions to the EPA's Greenhouse Gas Emissions Reporting Program. The charge starts at $900 per metric ton of methane, increasing to $1,500 after two years.

IV. Due to Its Underestimate of Methane Emissions From Oil and Gas Operations, the EPA Undervalues the Environmental and Economic Benefits of Methane Controls

The EPA made assumptions for how much the new rules may reduce methane leaks, based on the frequency of monitoring facilities using optical gas imaging (OGI) equipment. The criteria were outlined in a technical support document (TSD) that accompanied the initial NSPS proposed rules.[35] The OGI monitoring and repair assumptions for emissions reductions were 30% on a biennial frequency, 40% on an annual frequency, 60% on a semiannual frequency, 80% on a quarterly frequency, and 90% reductions on a monthly frequency. The frequencies and average reductions assumed changed in the Regulatory Impact Analysis of the Supplemental Proposal to: 45% reductions from annual monitoring, 67% reductions from semiannual monitoring, 77% reductions from quarterly monitoring, 81% reductions from bi-monthly monitoring, and 85% reductions achieved from monthly monitoring.

Tables 1 and 2 below present changes to the proved reserves valuations and proved reserves resulting from the three starting emissions rates (*i.e.*, EPA, Stanford, and Cornell) and the corresponding effects from leak reduction based on frequency scenarios for leak detection and repair solution deployed. The tables illustrate that underestimating methane emissions from oil and natural gas production materially suppresses an operator's ability to gauge the level of benefits arising from leak eliminations. For the XOP group, the benefits in both future volumes and valuations relative to using the EPA model to estimate original emissions increased by 60% under the Stanford study assumptions and by 122% under the Cornell study assumptions.

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[35] U.S. Environmental Protection Agency. U.S. EPA. Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Background Technical Support Document (TSD) for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG). October 2021.

Table 1: Projected Proved Reserves Valuation Increase Due to Methane Emission Reductions

	Original CH_4 Emission Estimates ($ billion)		
Reduction - OGI Frequency	EPA	Alvarez	Howarth
85% - Monthly	2.9	4.7	6.5
81% - Bi-monthly	2.8	4.4	6.2
77% - Quarterly	2.6	4.2	5.9
67% - Semiannual	2.3	3.7	5.1
45% - Annual	1.5	2.5	3.4

Source: Company reports, IEEFA Projections.

Table 2: Projected Proved Reserves Volume Increase Due to Methane Emission Reductions

	Original CH_4 Emission Estimates (BCF)		
Reduction - OGI Frequency	EPA	Alvarez	Howarth
85% - Monthly	1,923	3,078	4,282
81% - Bi-monthly	1,833	2,933	4,081
77% - Quarterly	1,742	2,788	3,879
67% - Semiannual	1,516	2,426	3,375
45% - Annual	1,018	1,629	2,267

Source: Company reports, IEEFA Projections.

The continued elevation of natural gas prices implies future cost benefit analysis decisions will ignore even larger benefits from methane reductions than what we have illustrated in our examples.

The EPA estimates compliance costs at $19 billion,[36] while the recovered products estimate is $4.6 billion (*i.e.*, the amount of leakage that is captured and then sold on the market). Both figures use a 3% discount rate over the 12 years analyzed. Dollar figure benefits to the climate are projected at $48 billion using the same criteria. Collectively, the EPA projects the net benefits of the proposed rule will be approximately $34 billion, or an annual equivalent of $3.2 billion for 2023 through 2035.

IEEFA projects that the EPA proposal understates recoverable products by 1,834 billion cubic feet. In 2019 dollars, the additional recovered products would be worth $4.3 billion to the industry (calculated using a 10% discount rate and a $6.25 price for natural gas for the 12-year period).

[36] On a per-barrel equivalent rate, the cost is approximately $0.18 per barrel of oil equivalent produced, using 2019 annual oil and gas production of 10.1 billion oil-equivalent barrels. The higher the total production, the lower the per-unit cost of deployment. The compliance cost per unit of production could decline if production continues to rise in the U.S.

Conclusion

The oil and gas industry and the EPA's undercounting of methane leaks has a silver lining. Once implemented, the new EPA regulations will produce results that exceed their own projections for methane emission reductions because these emissions were not considered in their original assessment.

IEEFA expects the rules would result in much greater emissions reductions than the 36 million short tons that the EPA's analysis projected over the next 12 years because of the agency's poor assumptions. Using emissions estimates instead of monitoring and measuring activities leads to severe emissions undercounting and low assumptions about what amount fugitive emissions can be prevented in the future. The anecdote from the House Committee on Science, Space and Technology in which one leak that occurred during their investigation of 10 Permian operators equaled 80% of the emissions that the firm with the leak reported in the prior year illustrates the point.

The quantity of methane leaks from U.S. oil and gas producers is unknown because leaks are sporadic and unpredictable. Most recent research studies are using point-in-time snapshots or evaluating historical data. The new rules provide the oil and gas industry with a financial "margin of safety," given the EPA's underestimate of emissions. Although IEEFA estimates the cushion will be about 60 percent or more above expectations, the actual amount of additional methane that would be captured and available for marketing as a result of compliance with the EPA's proposed regulatory scheme is currently unknown.

The ability of a company to control emissions should yield a commensurate proved reserves benefit. As better usage of LDAR technologies and other solutions required by the EPA are installed, we suspect a 1% to 5% incremental bump in natural gas production will follow from higher retentions. And since this bump will occur with relatively *de minimis* production and exploration costs, the EPA's adoption of the methane rules will assist operators in achieving higher future profit margins.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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