Congressional Budget Office
Nonpartisan Analysis for the U.S. Congress

How CBO Analyzes the Effects of Charging the Oil and Gas Industry for Methane Emissions

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At a Glance

Lawmakers recently imposed a charge for methane emitted by the oil and natural gas industry. In this report, the Congressional Budget Office outlines the nonbudgetary effects of such a charge and discusses how the agency generally analyzes them.

Methane is a potent greenhouse gas that has a much stronger warming effect than carbon dioxide but that remains in the atmosphere for a shorter period. The oil and gas industry is responsible for almost one-third of methane emissions from human activities in the United States. The production, processing, storage, and transportation of natural gas (which consists mainly of methane) account for most of the industry's methane emissions.

Accurately estimating methane emissions is a challenge. Current estimates are largely based on the equipment that companies use to produce and supply natural gas rather than on direct measurements. As a result, facilities with the same equipment-based estimates of emissions could emit very different amounts of methane, depending on how their equipment was operated.

The following are important aspects of CBO's analysis of the nonbudgetary effects of charging companies for methane emissions:

- **Charging for methane emissions affects the amount of emissions and companies' costs to produce natural gas.** How much those costs increase and how much emissions decrease depend on abatement costs and the details of the law and regulations establishing the charge, but a large percentage of emissions could probably be avoided at a low cost. Beyond that point, abatement costs would probably increase steeply.
- **Charging for emissions decreases the output and increases the price of natural gas.** The increase in natural gas prices depends on how sensitive end users are to such increases compared with producers' sensitivity to them. Because end users of natural gas are not as sensitive to price increases as its suppliers are, much of the cost for abatement is expected to be passed through to end users as a price increase. Because abatement costs are relatively low for a large percentage of emissions, the price increase and output decrease associated with abating that percentage is expected to be correspondingly small.
- **CBO's analysis of a methane charge depends on the details of the law and regulations establishing the charge.** The way methane emissions are estimated, the structure and timing of the charge, and the scope of emissions subject to it all determine how the charge affects emissions, companies' costs, and the price and output of natural gas.

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Summary

Methane is a greenhouse gas (GHG), which traps heat in the atmosphere. It has a stronger warming effect than carbon dioxide but remains in the atmosphere for a shorter period. To reduce emissions of methane, the 2022 reconciliation act (Public Law 117-169), signed into law on August 16, 2022, includes provisions to charge companies for methane emitted from their oil and gas operations.[1]

This report outlines the Congressional Budget Office's approach to analyzing the nonbudgetary effects of a charge for methane emissions. It generally describes how imposing such a charge affects emissions, companies' costs, and natural gas prices and discusses how CBO analyzes such a charge. It does not address the specific nonbudgetary effects of the 2022 reconciliation act, nor does it discuss the act's budgetary effects. (CBO estimates that the newly enacted charge will result in $6.35 billion in revenue to the government over fiscal years 2026 to 2031. For the purposes of assessing its budgetary and economic effects, a charge for methane emissions is considered an indirect tax.)[2]

Methane emissions account for 11 percent of the projected global warming effect of GHG emissions from human activities in the United States when those effects are measured over a 100-year period. When measured over a 20-year period, methane emissions represent an even greater share of the effects of GHG emissions. Methane is the main component of natural gas, and the oil and gas industry is responsible for almost one-third of methane emissions from human activities in the United States.

Unlike many pollutants emitted from smokestacks, which can be measured directly, methane emissions come from leaks and venting that occur throughout the supply chains for oil and natural gas. Therefore, rather than being measured directly on a large scale, methane emissions are usually estimated on the basis of the types of equipment in place at oil and natural gas facilities. But such equipment-based estimates do not include all methane emissions and may not be a precise measure of the methane emitted at individual facilities or by individual companies. For example, two facilities with identical equipment handling the same amounts of natural gas would have the same estimated emissions—and would therefore be charged the same amount—even if one of them emitted less methane because its operator was more careful to check for leaks.

How Does Charging for Methane Emissions Affect Emissions and the Market for Natural Gas?

Charging for methane emissions creates a financial incentive for companies to reduce emissions; however, companies' costs increase as they do so and pay the charge for remaining emissions. In general, companies will reduce methane emissions as long as the incremental cost of those reductions is less than paying the charge. Some of those cost increases are passed along to consumers of natural gas in the form of higher prices. The magnitude of the price increase depends on how sensitive consumers and producers are to changes in the market price of natural gas. On the one hand, research indicates that consumers are less sensitive to price changes than producers are and will therefore bear more of the burden of the cost increase from a charge. On the other hand,

1. See Congressional Budget Office, Estimated Budgetary Effects of H.R. 5376, the Inflation Reduction Act of 2022 (August 3, 2022), Table 6, www.cbo.gov/publication/58366.

2. Indirect taxes are imposed on goods and services rather than directly on wages, profits, or other forms of income. Indirect taxes, whether paid by firms or passed on to consumers, reduce a firm's net income and therefore reduce the amount available for direct taxation. As a consequence, CBO and the staff of the Joint Committee on Taxation generally apply a revenue offset to estimates of the budgetary effects of changes in indirect taxes such as excise taxes, customs duties, and compulsory governmental fees. For further information, see Congressional Budget Office, *The Role of the 25 Percent Revenue Offset in Estimating the Budgetary Effects of Legislation* (January 2009), www.cbo.gov/publication/20110.

studies suggest that companies have several low-cost options to install equipment and change operating practices to reduce methane emissions. Those options would result in a smaller impact on prices for consumers.

Although charging for methane emissions could affect some U.S. oil production, the following analysis focuses solely on effects on the market for natural gas. Because oil is traded on a global market, the effects of a charge for emissions on that market are probably negligible; moreover, estimated methane emissions from the natural gas supply chain are about four times those associated with oil production in the United States.

What Are the Major Considerations in Analyzing a Charge for Methane Emissions?

Several factors determine how a charge affects methane emissions, companies' costs, and the price of natural gas. Among those factors are the amount and timing of the charge, the companies and facilities subject to it, and the level (if any) below which emissions are exempt. In general, there is a trade-off between emissions abatement and compliance costs. Choices that lead to fewer emissions generally result in higher costs and larger increases in the price of natural gas.

Another important factor is how methane emissions are measured or estimated. Equipment-based estimates, such as those used by the Environmental Protection Agency's (EPA's) Greenhouse Gas Reporting Program (GHGRP), do not capture all methane emissions and may not be a precise measure of emissions at any given facility or by a company overall. A charge based on such estimates provides incentives to use lower-emitting or fewer pieces of equipment, but it does not create an incentive to reduce emissions in other ways, such as by detecting leaks and making repairs. Ongoing progress in remote sensing and atmospheric modeling may allow direct measurements of methane emissions on a wider scale in the future. In the meantime, there are other feasible options for estimating emissions, such as relying on improved equipment-based estimates.

Methane Emissions From Oil and Natural Gas Systems

Methane is a GHG that has a stronger warming effect than carbon dioxide (CO_2) but that persists for a shorter time in the atmosphere. A metric ton of methane has roughly 82 times the warming potential of a metric ton of CO_2 over a 20-year period and about 28 times the warming potential over a 100-year period.[3] The Intergovernmental Panel on Climate Change estimates that global methane emissions have been responsible for about 0.5 degrees Celsius of warming since the end of the 19th century.[4] In 2020, methane emissions accounted for 11 percent of the projected global warming effect of GHG emissions from human activities in the United States, when those effects are measured over a 100-year period. Over a shorter period, the importance of methane emissions among all GHG emissions is even greater.

According to EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks (hereafter referred to as EPA's greenhouse gas inventory), natural gas and oil systems are the source of 32 percent of total methane emissions from human activities in the United States.[5] Emissions in the oil and gas industry occur because of leaks and intentional venting of natural gas (which consists primarily of methane) and other sources of methane throughout the supply chain. The production, processing, transmission, storage, and distribution of natural gas all emit methane, as does the production of oil.

Methane may be released unintentionally or intentionally as a part of normal operations throughout the

3. When determining the global warming potential (GWP) of a greenhouse gas, climate scientists usually compare the gas's average warming effect over several years with that of carbon dioxide. The Environmental Protection Agency has estimated a GWP for methane of 27 to 30 times that of carbon dioxide over a 100-year period and a GWP of 81 to 83 times over a 20-year period; see Environmental Protection Agency, "Understanding Global Warming Potentials" (accessed July 28, 2022), https://tinyurl.com/muff95sv. In its Greenhouse Gas Inventory, EPA uses a GWP of 25 for methane to be consistent with the measure used by the Intergovernmental Panel on Climate Change.

4. The Intergovernmental Panel on Climate Change estimates that the net increase in human-caused global surface temperature since the end of the 19th century is 1.07 degrees Celsius. See Intergovernmental Panel on Climate Change, "Summary for Policymakers," in Valérie Masson-Delmotte and others, eds., *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, 2021* (IPCC, 2021), Figure SPM.2 and Paragraph A.1.3, https://tinyurl.com/6ur2atus.

5. The other major sources of methane emissions are agriculture and livestock (36 percent of emissions from human activities) and landfills (17 percent of emissions from human activities). See Environmental Protection Agency, "Overview of Greenhouse Gases" (accessed July 28, 2022), https://tinyurl.com/mrxejncj.

supply chain. Natural gas is actively released to maintain operating conditions through venting, and methane is passively emitted during certain operations. However, methane can also be unintentionally released because of malfunctioning equipment or abnormal operating conditions. For example, inspection hatches on tanks may be unintentionally left open, or flares that are meant to burn natural gas associated with oil production may go out.[6] Such abnormal conditions are thought to account for a large share of high-emitting events, which, in turn, account for a large proportion of overall emissions.[7]

Although emissions occur at every stage of the supply chain for natural gas—from production to local distribution—the following analysis, like recent legislative proposals, focuses on the upstream and midstream segments of the chain: exploration, production, processing, and transmission and storage. The production segment is responsible for about half of emissions from the oil and gas sector.

According to estimates from EPA's greenhouse gas inventory, the amount of methane emitted into the atmosphere decreased gradually from 2008 to 2020 because the leakage rate declined over that period. However, measuring methane emissions is difficult, and studies have estimated that actual emissions from the natural gas supply chain are greater than those reported in that inventory.[8] One study, for example, estimates that emissions are 60 percent higher than reported in EPA's greenhouse gas inventory.[9]

Total emissions from the oil and gas industry decreased by an estimated 3 percent between 2010 and 2020, whereas the production of natural gas increased by 51 percent. The leakage rate (that is, the average percentage of natural gas emitted as methane) has therefore fallen over time (see Figure 1), which could suggest that measures to limit emissions have improved.[10]

The unpredictable nature of methane emissions from the oil and gas supply chains makes them difficult to monitor and measure accurately, especially at individual facilities. The supply chain is highly dispersed, making it difficult to detect and measure emissions with a high level of geographic precision throughout the entire system. For that reason, current reporting on facility-level emissions relies largely on counts of equipment combined with average emissions factors.[11]

However, emissions may occur along parts of the supply chain that are not directly monitored. Moreover, high-emitting events occur unpredictably and inconsistently, and the same types and makes of equipment can emit methane at very different rates, depending on their condition and the way they are operated. Those complications reduce the reliability of an equipment-based approach for measuring emissions. The quality of efforts

6. The methane emitted from venting natural gas has a larger impact on the climate than does the CO_2 from flaring an equivalent amount of natural gas. See, for example, Raphael Calel and Paasha Mahdavi, "The Unintended Consequences of Antiflaring Policies—and Measures for Mitigation," *Proceedings of the National Academy of Sciences*, vol. 117, no. 23 (June 9, 2020), pp. 12503–12507, https://doi.org/10.1073/pnas.2006774117.

7. There is no single, agreed-upon definition of a high-emitting event or site; thus, different studies use that term on the basis of different thresholds. Those thresholds are usually based on an amount of leakage over a period of time (emissions per hour) or in proportion to an amount of natural gas produced. See, for example, Daniel Zavala-Araiza and others, "Super-emitters in Natural Gas Infrastructure Are Caused by Abnormal Process Conditions," *Nature Communications*, vol. 8, no. 14012 (January 2017), pp. 1–10, https://doi.org/10.1038/ncomms14012. In that study, a high-emitting site is defined as one where at least 26 kilograms of methane per hour are emitted, corresponding to the top 1 percent of sites in the study.

8. See, for example, Ramón A. Alvarez and others, "Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain," *Science*, vol. 361, no. 6398 (June 2018), pp. 186–188, https://doi.org/10.1126/science.aar7204; and Jeffrey S. Rutherford and others, "Closing the Methane Gap in U.S. Oil and Natural Gas Production Emissions Inventories," *Nature Communications*, vol. 12, no. 4715 (August 2021), pp. 1–12, https://doi.org/10.1038/s41467-021-25017-4.

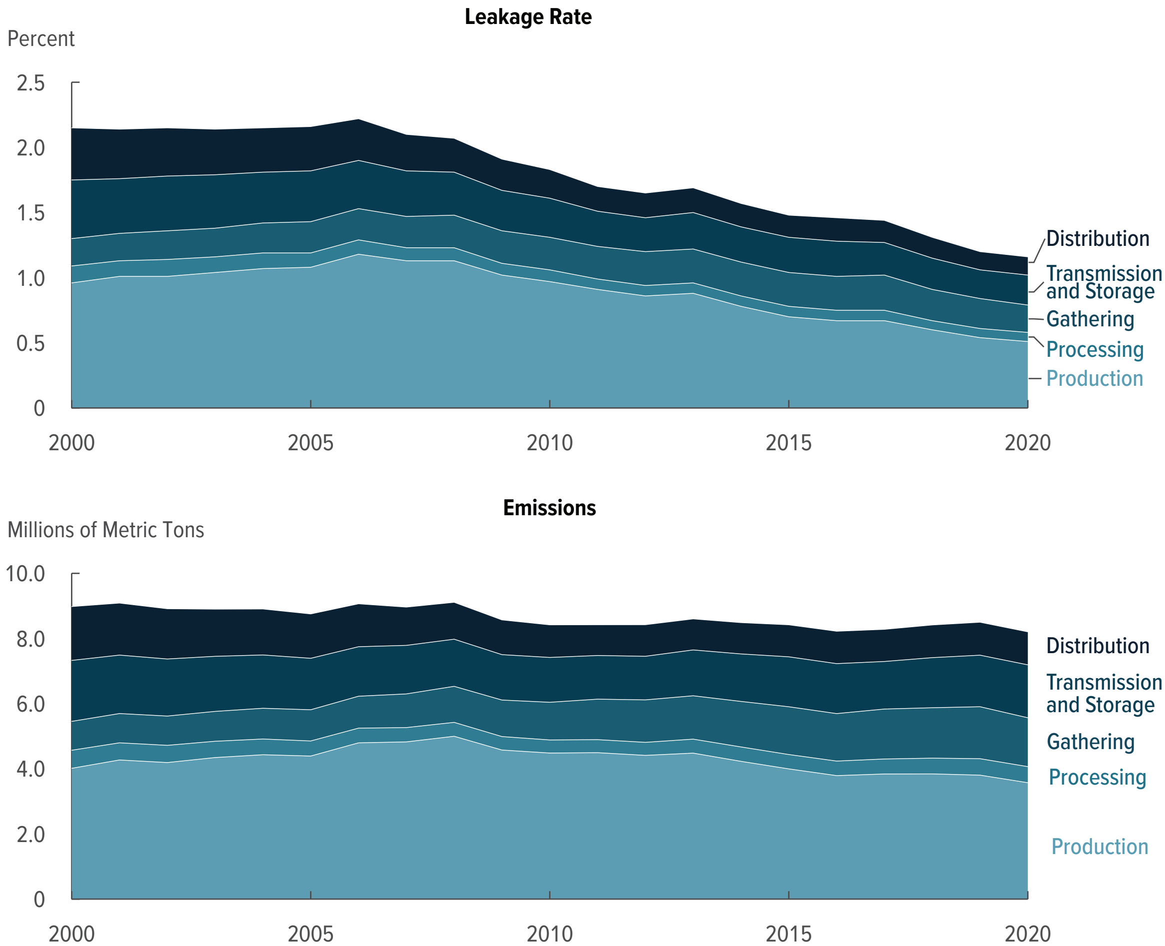
9. See Ramón A. Alvarez and others, "Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain," *Science*, vol. 361, no. 6398 (June 2018), pp. 186–188, https://doi.org/10.1126/science.aar7204.

10. Calculations in this analysis use a conversion rate of 0.0192 metric tons of methane per thousand cubic feet and are based on natural gas's having an average methane content of 90 percent. For the conversion rate, see Mandatory Greenhouse Gas Reporting, Calculating GHG Emissions, 40 C.F.R. §98.233 (2022). For the average methane content, see Ramón A. Alvarez and others, "Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain," *Science*, vol. 361, no. 6398 (June 2018), pp. 186–188, https://doi.org/10.1126/science.aar7204.

11. An average emissions factor is an estimate of how much methane is released by a piece of equipment during a certain amount of activity, such as handling a certain volume of natural gas, operating for a certain duration, or performing a certain operation once.

Figure 1.

Leakage Rate and Emissions of Methane From the Oil and Gas Sector



Data source: Congressional Budget Office, using data from the Environmental Protection Agency's Greenhouse Gas Inventory and from the Energy Information Administration. See www.cbo.gov/publication/58166#data.

All leakage rates are reported as metric tons of methane emitted into the atmosphere, divided by the methane content of gross U.S. natural gas withdrawals. Estimates of total emissions come from Tables 3-69 and 3-43 in the Environmental Protection Agency's (EPA's) Greenhouse Gas Inventory; see Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020* (April 2022), https://tinyurl.com/4xadu26d. Emissions from petroleum systems are included in the category "Production." Postmeter emissions (that is, emissions that occur after an end user's consumption of natural gas has been measured) are included in the category "Distribution." Leaks from malfunctioning equipment and operational errors are not reflected in EPA's Greenhouse Gas Inventory.

to monitor and measure emissions is an important determinant of the effects of imposing a charge for emissions.

How Charging for Methane Emissions Affects Emissions and the Market for Natural Gas

A charge for methane emissions decreases the amount of methane emitted and increases the cost of producing natural gas, which raises its price and lowers its total output. Studies of the oil and gas industry have found that companies have low-cost options for reducing a large percentage of methane emissions, but abatement costs increase steeply once those options are exhausted. Because end users of natural gas are not as sensitive to price increases as its suppliers are, much of the cost for abatement is expected to be passed through to end users as a price increase. That price increase will represent a smaller percentage of the total bill for users who pay higher markups for natural gas, such as residential users, than for those that pay lower markups, such as companies that produce electric power.

Some U.S. oil production could be affected by a charge for methane emissions because oil and natural gas are often comingled underground. However, this analysis does not address effects on the price and output of oil, for two reasons. First, EPA's greenhouse gas inventory estimates that emissions of methane from U.S. oil production amount to about one-fourth of those coming from the supply chain for natural gas.[12] Second, because oil is traded on a global market, the effects on the price of crude oil would probably be negligible. That small price response means that oil producers would essentially absorb the full cost of abating emissions and paying the charge or would reduce their output.

Effects on Emissions and Companies' Costs

Charging for methane emissions creates an economic incentive for companies to reduce emissions. Because a company pays for each unit of methane it emits, it will reduce emissions up to the point at which the cost of doing so exceeds the charge and only pay the charge for its remaining emissions. The expense of producing natural gas will increase by the combined cost of the reduction in emissions and the amount charged on remaining emissions. Because methane emissions are often associated with a loss of marketable natural gas, some of that expense will be offset by the value of capturing the gas that would otherwise have been lost.[13]

A company's increased expense is expected to be passed through, in part, to end users in the form of higher prices. Those higher prices will reduce natural gas consumption, which will also reduce methane emissions to some extent. Because there are many low-cost opportunities to reduce the rate of methane emissions, most of the decrease in emissions from imposing a charge is likely to come from measures to reduce that rate rather than from end users' reduced consumption of natural gas. The effect of a charge would change if new regulations or other policies were adopted that also influenced emissions (see Box 1).

12. See Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020,* EPA 430-R-22-003 (April 2022), https://tinyurl.com/4xadu26d.

13. That value is unlikely to fully offset the cost of reducing emissions: If an action to reduce emissions was profitable, the company would already be taking that action. For further discussion, see Levi Marks, "The Abatement Cost of Methane Emissions From Natural Gas Production," *Journal of the Association of Environmental and Resource Economists*, vol. 9, no. 2 (March 2022), pp. 165–198, https://tinyurl.com/nhh4w7tz.

The cost of reducing each successive metric ton of methane emissions depends on how much emissions have already been reduced. That relationship between incremental cost and remaining emissions can be summarized by a marginal abatement cost curve.[14] Some studies suggest that a large share of emissions can be eliminated at a relatively low cost, but that the cost of additional reductions would increase very rapidly after that. Thus, the cost curve is usually viewed as being shaped like a hockey stick (see Figure 2). One study of natural gas production estimates that the marginal abatement cost for 60 percent of EPA-estimated methane emissions ranges from zero to $150 per metric ton (which equals about $4 per CO_2-equivalent metric ton), net of the value of the captured natural gas.[15] Most of the reductions would cost much less than $150 per metric ton. However, the marginal cost would then begin to increase steeply, making further reductions much more expensive.[16] For example, according to that study, once the lowest-costing 74 percent of emissions were eliminated, the next metric ton of methane would cost about $1,400 (about $41 per

14. A marginal abatement cost curve organizes emission reductions from least costly to most costly and plots the cumulative reductions achieved against the cost of reducing an additional ton of emissions. As companies exhaust lower-cost options to reduce emissions, additional reductions become increasingly costly. Faced with a charge for methane emissions, a company would generally reduce its emissions until the marginal cost of abatement equaled the charge.

15. A CO_2-equivalent metric ton of methane is equal to a metric ton of methane multiplied by the ratio of the global warming potential of methane to that of carbon dioxide. See Levi Marks, "The Abatement Cost of Methane Emissions From Natural Gas Production," *Journal of the Association of Environmental and Resource Economists*, vol. 9, no. 2 (March 2022), pp. 165–198, https://tinyurl.com/nhh4w7tz. Notably, that study uses a 100-year global warming potential of 34 for methane.

16. Other research finds a similar hockey-stick-shaped marginal abatement cost curve for the natural gas transmission segment, which includes long-distance pipelines and the associated compressor stations. See Erin N. Mayfield, Allen L. Robinson, and Jared L. Cohon, "System-Wide and Superemitter Policy Options for the Abatement of Methane Emissions From the U.S. Natural Gas System," *Environmental Science and Technology*, vol. 51, no. 9 (February 2017), pp. 4772–4780, https://tinyurl.com/svb5ux89. For additional estimates of methane abatement costs that exhibit the same general shape, see International Energy Agency, "Methane Tracker Data Explorer" (February 23, 2022), www.iea.org/articles/methane-tracker-data-explorer; and ONE Future Inc., *Economic Analysis of Methane Emission Reduction Potential From Natural Gas Systems* (prepared by ICF International, May 2016), https://tinyurl.com/2av2d4f6 (PDF, 598 KB).

Box 1.

Interactions Between a Charge for Methane Emissions and Proposed Regulatory Changes

In November 2021, the Environmental Protection Agency published draft rules for existing and new sources of methane emissions in the oil and gas industry.[1] Those proposed regulations largely prescribe the use of certain technologies (such as pneumatic valves that do not vent natural gas to open and close) and operating practices (such as more frequently detecting leaks and making repairs to reduce emissions).

If those regulations were implemented without major changes to the structure of the draft rule, the incremental effects of charging for methane emissions would be diminished. First, some of the reductions in emissions that a charge would induce in the absence of such regulations would occur because of the regulations. However, the regulations target specific technologies and practices; therefore, charging for emissions would still give companies an incentive to pursue any low-cost measures to abate emissions not covered by the regulations. Second, the cost to companies stemming from a charge would be reduced because some of the emissions abatement would be required by the regulations; however, companies would still incur the cost of any additional reductions in emissions and would also pay the charge for any remaining emissions.

All told, a charge for methane emissions will still increase companies' costs and the price of natural gas and will still reduce emissions and the total amount of natural gas produced. However, the incremental effects of the charge will be smaller than they would be in the absence of the new regulations.

If the charge was waived for facilities that are covered by and compliant with the regulations, the Congressional Budget Office would account for that waiver in its analysis. In that case, once the regulations were approved and implemented, the charge would have no incremental effect on the costs or emissions of the compliant facilities.

1. Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63110 (proposed November 15, 2021), https://tinyurl.com/5n9845v2.

CO_2-equivalent metric ton) to abate, net of the value of the captured gas.[17]

One useful point of comparison is the estimate of the social cost of methane provided by the Interagency Working Group on the Social Cost of Greenhouse Gases.[18] The social cost of methane is defined as the net present monetary value of the harm to society from incrementally increasing emissions by one metric ton—a value that the working group estimated to be $1,500 per metric ton in 2020, under the assumption that future benefits are discounted at 3 percent annually. Executive branch agencies have been directed to use that estimate to monetize the value of changes in methane emissions.[19]

Estimates of abatement costs in the research literature are largely based on current technologies or companies' historical responses to incentives to reduce methane leaks. A policy establishing a permanent charge for emissions strengthens the incentives for firms to innovate and discover new low-emissions technologies and processes. As a result, the cost per ton to reduce emissions could be less in the future, which would result in additional reductions of emissions and lower costs to companies.

Because charging for methane emissions increases the price of natural gas, purchasers of natural gas might respond to higher prices by replacing it with other energy

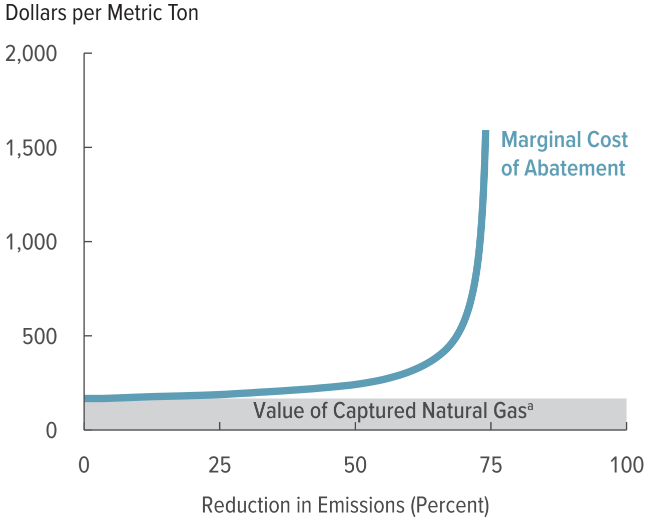
17. Section 60113 of the 2022 reconciliation act sets a charge of $900 per metric ton of emissions reported for 2024, $1,200 per metric ton for 2025, and $1,500 per metric ton thereafter.

18. The Interagency Working Group on the Social Cost of Greenhouse Gases is a working group with members from several executive branch agencies. It was most recently reestablished under Executive Order 13990 and is co-chaired by the Chair of the Council of Economic Advisers, the Director of the Office of Management and Budget, and the Director of the Office of Science and Technology Policy. See Interagency Working Group on Social Cost of Greenhouse Gases, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* (February 2021), https://tinyurl.com/5cxz2jpu (PDF, 2.4 MB), and Exec. Order No. 13990, 86 Fed. Reg. 7037 (January 25, 2021), https://tinyurl.com/59vknyvw.

19. Exec. Order No. 13990, 86 Fed. Reg. 7037 (January 25, 2021), https://tinyurl.com/59vknyvw.

Figure 2.

An Estimate of the Marginal Cost of Abating Methane Emissions From Natural Gas Production



Data source: Congressional Budget Office, adapting data from Levi Marks, "The Abatement Cost of Methane Emissions From Natural Gas Production," *Journal of the Association of Environmental and Resource Economists*, vol. 9, no. 2 (March 2022), pp. 165–198, https://tinyurl.com/nhh4w7tz.

This figure presents emissions estimated using the Environmental Protection Agency's Greenhouse Gas Reporting Program. For more information about that program, see Environmental Protection Agency, "Greenhouse Gas Reprting Program (GHGRP)" (accessed July 18, 2022), www.epa.gov/ghgreporting.

a. The value of natural gas is converted to dollars per metric ton of methane to account for the fact that natural gas does not consist entirely of methane.

sources. More or less CO_2 might be emitted in producing energy using those other sources. Producers of electricity, for example, could respond to higher natural gas prices by using other technologies to generate electricity. Coal-generated electricity produces about twice as much CO_2 as electricity produced using natural gas (for the same amount of heat output), which would offset some of the reduced emissions from using less natural gas.[20] However, electric power producers could also switch from natural gas to renewable energy, which emits no CO_2. The ultimate result would probably be a mix of those two responses, with the sector partly replacing natural gas with (higher-CO_2-emitting) coal and partly with (lower-CO_2-emitting) renewable energy sources.

Effects on the Price and Output of Natural Gas

Charging for methane emissions leads to an increase in the price of natural gas and a decrease in the quantity of natural gas produced and consumed. And in general, as costs to abate emissions increase or decrease, so do the charge's effects on price and quantity. The magnitude of those effects also depends on how sensitive different end users are to changes in the price of natural gas. The price increase will vary as a percentage of end users' total bills because some end users pay higher markups than others for distribution and administrative services.

The Energy Information Administration of the Department of Energy classifies end users of natural gas in five categories: residential, commercial, industrial, electric power, and transportation. Residential and commercial purchasers use natural gas for things like heating water and buildings and for cooking. Industrial firms use it as a fuel for furnaces and boilers to make heat in manufacturing or as a feedstock in chemical reactions to produce derived chemical products. (For example, natural gas is used to create ammonia, which is a primary component of fertilizer.) Power companies use natural gas to drive turbines that generate electricity. The transportation sector uses some natural gas to fuel vehicles and a far greater amount of it to operate pipelines and distribute the gas itself.[21]

How charging for emissions affects the prices faced by end users and the consumption of natural gas depends on the relative price elasticities of supply and demand for various end users. Price elasticities measure how responsive a quantity of something demanded or supplied is to a given change in price. For example, a price elasticity of demand equal to –0.5 means that if the price of natural gas increased by 10 percent, the quantity of natural gas demanded would fall by 5 percent. The burden of a charge (or tax) is generally borne by producers or consumers on the basis of how sensitive they are to changes in price; the less sensitive group absorbs more of the

20. See Energy Information Administration, "Carbon Dioxide Emissions Coefficients by Fuel" (updated February 9, 2022), https://tinyurl.com/eft4uvmh.

21. Because the transportation category of end users mostly represents consumption by components of the natural gas supply chain itself, that category is omitted from the remainder of this analysis. In 2021, total consumption by the transportation sector represented about 3 percent of total natural gas consumption. See Energy Information Administration, *August 2022 Monthly Energy Review* (August 25, 2022), Table 4.3, www.eia.gov/totalenergy/data/monthly/.

Table 1.

Estimated Price Elasticities of Demand for and Supply of Natural Gas

	Demand				
	Residential	Commercial	Industrial	Electric Power	Supply
EIA—NEMS[a]	-0.23	-0.28			
Bernstein and Griffin[b]	-0.36				
Arora[c]	-0.24				0.42
Hausman and Kellogg[d]	-0.20	-0.23	-0.57	-0.47	0.81
CBO[e]	-0.26	-0.28	-0.26	-0.58	
Average	**-0.26**	**-0.26**	**-0.42**	**-0.53**	**0.62**

Data source: Congressional Budget Office, using data from the various sources noted below. See www.cbo.gov/publication/58166#data.

Price elasticities measure how responsive a quantity of something demanded or supplied is to a given change in price. For example, a price elasticity of demand equal to -0.5 means that if the price of natural gas increased by 10 percent, the quantity of natural gas demanded would fall by 5 percent. All estimates of price elasticities are long-run estimates. Blank cells in the table indicate instances in which the study did not estimate or did not report the relevant elasticity.

EIA = Energy Information Administration; NEMS = National Energy Modeling System.

a. Energy Information Administration, *Price Elasticity for Energy Use in Buildings in the United States* (January 2021), https://tinyurl.com/5cdshcd4. The demand elasticities from the Energy Information Administration's National Energy Modeling System come from documentation about demand elasticities in the buildings sector.

b. Mark A. Bernstein and James Griffin, *Regional Differences in the Price-Elasticity of Demand for Energy* (RAND Corporation, 2005), https://tinyurl.com/3drrkc42.

c. Vipin Arora, *Estimates of the Price Elasticities of Natural Gas Supply and Demand in the United States*, Working Paper 54232 (Munich Personal RePEc Archive, 2014), https://mpra.ub.uni-muenchen.de/54232/.

d. Catherine Hausman and Ryan Kellogg, "Welfare and Distributional Implications of Shale Gas," *Brookings Papers on Economic Activity* (Spring 2015), pp. 71–139, https://tinyurl.com/bde4pz66.

e. The Congressional Budget Office estimated elasticities using a method similar to that used in Hausman and Kellogg but with more years of data. Those estimates were calculated specifically for this report to replicate previous findings and update them with more recent data. CBO did not update the supply elasticity because necessary data are not available.

charge. For example, if demand was perfectly inelastic (meaning that the same amount of natural gas would be purchased no matter the price), consumers would pay the full amount of the charge in the form of a higher price. But if supply was perfectly inelastic (meaning that the quantity of natural gas produced would remain the same no matter the price), producers would pay that full amount in the form of a lower price received, net of the charge. In practice, the outcome is likely to be somewhere between those two extremes.

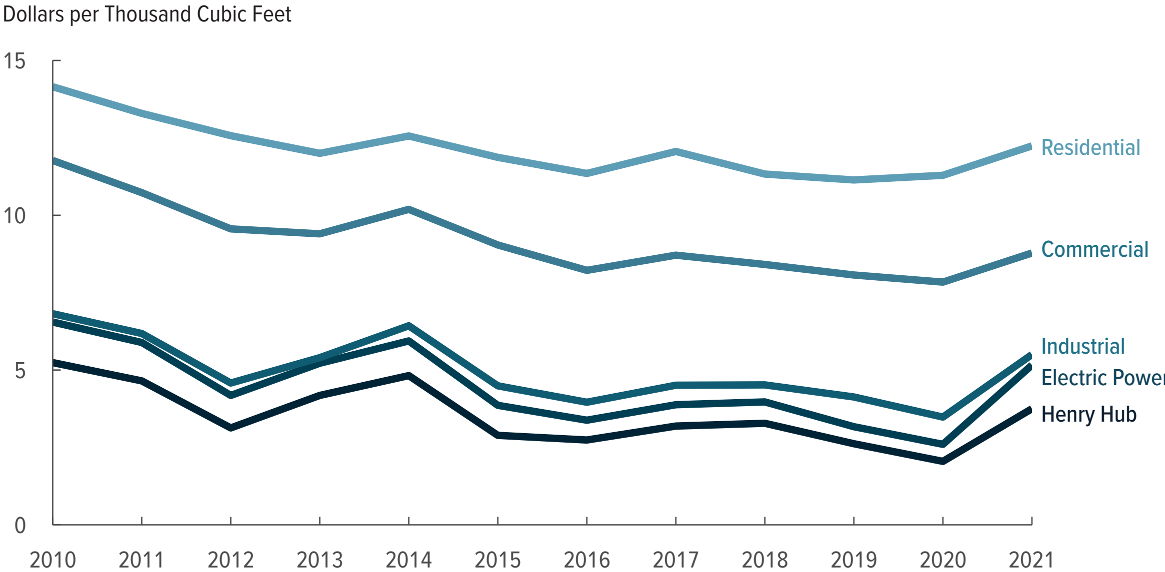
Demand from residential and commercial end users is less elastic than demand from producers of electric power (see Table 1). And supply is generally more sensitive to price than demand. Those relative elasticities suggest that the end users will bear more of the cost increase from a charge for methane emissions by paying higher prices. However, producers will still bear some of the burden of the charge because the increase in their costs is not fully offset by the increase in price.

Differences in companies' emissions rates and abatement costs also affect how much of the burden of a methane charge they bear. Although prices of natural gas vary regionally in the United States, they are nonetheless determined by the market. Thus, although different companies experience the same price increase from a charge, those with higher abatement costs and emissions rates are more adversely affected, on net, because they either need to absorb more of those cost increases in order to continue to sell at the market price or reduce their output.

Furthermore, differences in companies' costs could also affect the magnitude of the price increase itself. Facilities that have higher overall marginal costs are less profitable at a given market price and therefore will probably be among the first to reduce production. If those higher-cost facilities also had higher abatement costs and higher emissions rates, the price increase (and thus the burden on consumers) would be larger because the charge would prevent more natural gas from being

Figure 3.

Prices of Natural Gas for End Users and the Henry Hub Spot Price of Natural Gas



Data source: Congressional Budget Office, using data from the Energy Information Administration. See www.cbo.gov/publication/58166#data.

All prices are expressed in 2021 dollars, using the consumer price index for all urban consumers from the Bureau of Labor Statistics. The Henry Hub spot price reflects the wholesale price of natural gas. (Prices at Henry Hub—a major pipeline interconnection in Louisiana—are generally used as benchmarks for pricing throughout the entire North American natural gas market.) The end use of natural gas as a fuel for vehicles is omitted; that use constitutes only 0.2 percent of total natural gas consumption in the United States.

produced. But if those facilities had lower abatement costs and lower emissions rates, the price increase would be smaller because the production on the margin would not be affected.

Natural gas prices vary among the different categories of end users, and the commodity cost of natural gas (that is, the wholesale cost of gas excluding distribution costs) makes up a varying share of those prices. Prices for residential and commercial end users are the highest, reflecting the small amounts of gas that individuals tend to buy and the more complicated distribution networks needed to supply them (see Figure 3). Industrial end users and electric power end users pay the lowest prices for natural gas because they buy in large volumes concentrated in specific areas, enabling them to negotiate contracts with lower prices. About 70 percent of the price that residential end users pay reflects markups from utility companies to pay for distribution and administrative costs. And, on average, changes in the wholesale price of natural gas are passed directly to end users.[22] Consequently, any increase in wholesale prices causes end-use prices to rise by the same amount. For providers of electric power, each 1 cent increase in the price of natural gas represents a 0.3 percent increase in their natural gas costs (on the basis of 2021 prices); however, that same increase results in only a 0.1 percent increase in a residential end user's total gas bill, which also includes the markups for distribution and administration charged by public utilities.

Although households purchase natural gas directly for in-home use, they also buy products from companies that use natural gas. For example, power companies sell electricity, industrial end users sell products like fertilizer, and commercial end users sell goods and services through retail shops and restaurants. Those nonresidential end users are expected to pass some or all of higher natural gas prices through to households in the form of the final prices for their goods.[23] The amount of the increase depends on the relative price sensitivities of supply and demand in those markets. However, fuel costs represent roughly 10 percent to 20 percent of retail electricity

22. Catherine Hausman and Ryan Kellogg, "Welfare and Distributional Implications of Shale Gas," *Brookings Papers on Economic Activity* (Spring 2015), pp. 71–139, https://tinyurl.com/bde4pz66.

23. See, for example, Dorian Carloni and Terry Dinan, *Distributional Effects of Reducing Carbon Dioxide Emissions With a Carbon Tax*, Working Paper 2021-11 (Congressional Budget Office, September 2021), www.cbo.gov/publication/57399.

prices, and natural gas costs only represent a portion of the prices charged for industrial output. Thus, even if nonresidential end users fully passed the increase in their costs through to households, those increases would represent only part of the price increase of natural gas on a percentage basis. For example, if fuel costs increased by 4 percent, then prices of electricity would increase by about 1 percent if those costs were fully passed through to the final consumer.

Analyzing the Effects of Charging for Methane Emissions

The main factors in analyzing the effects of charging for methane emissions are the amount of emissions subject to the charge and the amount of the charge over time. The amount of emissions subject to the charge is affected by the way emissions are estimated, which facilities are covered, and whether some benchmark rate of emissions is exempt. Each factor affects how much emissions are reduced, companies' costs, and the price and output of natural gas.

Emissions Subject to the Charge

Implementing a charge for methane emissions requires an estimate of emissions from each company or facility subject to the charge. How the estimates are calculated affects the analysis of the effects of the charge. EPA's current program for collecting facility-level data has significant limitations that reflect many of the difficulties associated with identifying emissions from individual sources at the necessary scale. Section 60113 of the 2022 reconciliation act instructs EPA's Administrator to revise that program within two years, and to modify it as necessary thereafter, to accurately reflect empirical data and facilities' emissions, but it does not specify how to do so. The way emissions are defined and measured has a large impact on the effect of a charge for emissions, companies' costs, downstream prices (that is, the prices paid by end users), and total natural gas output.

Current Approaches to Measuring Methane Emissions. Accurate company- or facility-level estimates of methane emissions are challenging to produce. Methane is emitted at many different points along the supply chain, it is often emitted unintentionally, and a large share of emissions can come from a relatively small number of facilities and from high-emitting events that are difficult to predict. However, implementing a charge for methane emissions requires company- or facility-level estimates as a basis for calculating payments.

EPA currently estimates facility-level methane emissions through the Greenhouse Gas Reporting Program, but that program is not presently designed to set prices on emissions. The GHGRP takes a bottom-up, equipment-based approach: Facilities report the equipment used, the amount of natural gas handled or the number of hours the equipment operates, and an estimate of methane emissions on the basis of average emissions factors.[24] For example, some pneumatic control valves use pressurized gas in the pipeline to open and close and therefore emit natural gas when they operate. Replacing a gas-powered valve with an electric-powered one would thus reduce estimated emissions, according to the GHGRP. However, monitoring hatches that are used to inspect and maintain storage tanks to ensure they are properly closed would not reduce estimated emissions under the GHGRP, because no new equipment was installed (or old equipment uninstalled) in that case, even though such monitoring could prevent high-emitting events. Moreover, only facilities that emit more than 25,000 CO_2-equivalent metric tons of greenhouse gases are required to report emissions under the program.

There are alternative approaches to measuring methane emissions. Some studies have directly measured emissions from a sample of individual facilities and used the results to estimate a distribution of facility-level emissions. Other studies have estimated emissions using measurements of methane concentrations taken by satellite or aircraft combined with atmospheric modeling.[25] Such approaches could provide useful information to improve facility-level estimates of emissions, but they would currently be difficult or very expensive to use in producing individual estimates for a large number of facilities.

Options for Estimating Emissions. Any analysis of the effects of charging for methane emissions depends greatly on the way emissions are estimated. In general, the more closely that estimated emissions reflect actual emissions, the stronger the incentive is for companies to reduce

24. The GHGRP requires direct measurements of emissions in a limited set of circumstances. See Environmental Protection Agency, "How Are Greenhouse Gas Emissions Calculated for Subpart W (Oil and Natural Gas Systems) Facilities?" (accessed June 28, 2022), https://tinyurl.com/yjb2nxvb.

25. For an analysis comparing aggregate results based on those two approaches, see Mark Omara and others, "Methane Emissions From Natural Gas Production Sites in the United States: Data Synthesis and National Estimate," *Environmental Science and Technology*, vol. 52, no. 21 (September 2018), pp. 12915–12925, https://doi.org/10.1021/acs.est.8b03535.

those emissions under a policy that established a charge for them. Although direct and accurate facility-level monitoring is probably infeasible at present, there are still several ways to estimate emissions to help reduce them.

Equipment-Based Estimates. One approach would use the GHGRP as the basis for the charge for emissions. The GHGRP provides equipment-based estimates of emissions for each reporting facility. To the extent that the emissions factors in the GHGRP are inaccurate, the emissions subject to the charge could be very different from actual emissions, even on average. Such an approach would naturally give companies an incentive to make changes that reduced their emissions as estimated under the GHGRP. Because of that program's design, the changes would largely involve installing and using equipment associated with lower emissions factors. However, the effects of switching to lower-emissions equipment could differ depending on operating conditions and procedures.

Although replacing equipment may reduce average emissions, some facilities might achieve much larger reductions than those for which they are credited, and others might achieve very small reductions or even increase emissions, depending on operating conditions. Furthermore, such an approach to estimating emissions would not provide a broad incentive to reduce them; for example, companies might choose not to reduce emissions by improving operating protocols that might prevent high-emitting events because doing so would not affect the amount they were charged. Therefore, two otherwise identical companies that took very different approaches to avoiding emissions could have very different emissions but still be charged the same amount for them. Finally, charging for emissions on the basis of a self-reported inventory could create an incentive to underreport equipment and activity levels.

If the GHGRP's emissions factors were updated to reflect the newest scientific evidence, estimated emissions would probably be revised upward, on average, because recent studies have shown that existing equipment-based estimates do not fully reflect actual emissions.[26] Compared with a charge for methane based on current emissions factors, a charge based on updated emissions factors would lead to lower emissions, higher company costs, larger increases in the price of natural gas, and larger decreases in its output. If the updated factors better reflected actual emissions than did the current factors, then the incentive to reduce emissions would be strengthened, and emissions would be lower still.

Equipment-Based Estimates Adjusted to Match Aggregate Estimates. A second approach would proportionally scale up a facility's GHGRP-estimated emissions so that the total emissions of all facilities matched an aggregate estimate based on direct measurement. That aggregate estimate could include the average effect of emissions from high-emitting events. That way, even if emissions were underestimated in the GHGRP, the total emissions to which the charge applied would be accurate. For example, if the total GHGRP-based estimate for all facilities was only half of a directly measured aggregate estimate of emissions, each facility's equipment-based estimate would be doubled for the purpose of calculating the charge.

Such an approach would create the same basic incentive structure as an approach based solely on the GHGRP, but those incentives would be stronger because estimated emissions would be scaled up to match the aggregate emissions estimate. Any action that reduced GHGRP-estimated emissions would allow companies to avoid the scaled-up charge, creating a stronger incentive to do so. Moreover, the charge for the remaining GHGRP emissions would be scaled up as well, resulting in a larger effect on companies' costs and the price and output of natural gas. To the extent that reducing GHGRP-estimated emissions reduced actual methane emissions, those would fall by more as well.

Company-Level Estimates Based on Random Sampling. A third approach would estimate each company's overall emissions by directly measuring them at a randomly selected subset of its facilities. The charge to the company would then be calculated on the basis of that overall estimate.[27] The random sampling would give companies an incentive to reduce emissions at all of their facilities. The cost of sampling only a share of facilities would be less than measuring emissions at all of them,

26. See, for example, Jeffrey S. Rutherford and others, "Closing the Methane Gap in U.S. Oil and Natural Gas Production Emissions Inventories," *Nature Communications*, vol. 12, no. 4715 (August 2021), https://doi.org/10.1038/s41467-021-25017-4.

27. This approach is analyzed in Levi Marks, *A Sampling-Based Approach to Emissions Pricing*, Working Paper (June 2018), www.levimarks.com/research. For more details on implementing this approach, see Levi Marks and Tom L. Green, *When the Price Is Right: How B.C.'s Carbon Tax Could Cost-Effectively Reduce Methane Pollution in the Oil and Gas Industry* (David Suzuki Foundation, August 2019), https://tinyurl.com/mw863a4c.

so a sampling-based approach might be feasible sooner than a comprehensive approach. The precision of a random sample increases with the sample size, so estimates would be less likely to be accurate for companies with fewer facilities. And because the estimate would be based on a subsample of facilities, some companies might be charged for more than their actual emissions. To alleviate those concerns, the charge could be based on a default emissions rate for companies with facilities below a certain number, or it could be based on sampling a larger share of their facilities.

Estimates Based on an Average Emissions Rate With Opt-In Monitoring. Finally, a fourth approach would use an average emissions rate estimated for all facilities in a given geographical area as a default but would allow companies to opt in to a detailed, well-defined monitoring and measurement protocol.[28] Such a protocol would depend on improvements in technology used for monitoring and the development of systematic reporting standards.[29] The option to join a monitoring protocol would provide an incentive for low-emitting companies to be charged on the basis of their own emissions rate rather than the higher average rate, assuming the cost of monitoring was not too high. After a tranche of companies opted in to monitoring, the average rate of methane emissions would be updated to reflect only emissions from the remaining companies, and that higher rate would be applied to those companies. As more companies monitored and reported their own emissions, the remaining companies' emissions subject to a charge would continue to rise, creating an even stronger incentive for high-emitting facilities to abate emissions.

In principle, the approach would work similarly for a default emissions rate computed across large or small geographical areas. It may be desirable to base the default rate on empirical estimates of average methane emissions from discrete geological basins (geological formations sometimes used to define regions of oil and gas production); such estimates are currently feasible. If the default rate was based on a larger-scale average, such as the average of an entire region (or even a national average), it would probably rely on an aggregation of basin-level measurements in any case. If the default rate was based on a smaller-scale average, the approach would face challenges similar to those experienced by approaches that rely on facility- and company-level monitoring and measurement.

In general, a charge imposed using more precise and accurate monitoring protocols increases companies' incentives to reduce emissions, resulting in a policy that achieves a given amount of reduction at lower cost and with a smaller effect on downstream prices than a policy based on average emissions factors. It also more closely links actual emission reductions with estimated emission reductions. However, implementing such an approach would be challenging without improvements in the way methane emissions were monitored and reported.

Amount and Timing of the Charge

The amount companies are charged for emissions determines the strength of their incentive to reduce emissions. A higher charge leads to fewer emissions, greater costs for companies, and larger increases in the price of natural gas. The magnitude of those effects depends on the cost of reducing emissions and the elasticities of supply and demand.

The effect of increasing the amount of the charge is illustrated by the movement up the hockey-stick-shaped marginal abatement cost curve (see Figure 2 on page 7). As the charge increases and companies undertake abatement efforts that cost less than the charge, further reducing emissions becomes more expensive. And because the curve becomes steeper, the expense increases more quickly as the charge is raised.

When the charge for emissions is at the lower end of the scale, the curve is relatively flat, so each successive opportunity to reduce emissions is only slightly more expensive than the previous one. On that part of the marginal abatement cost curve, an incremental increase in the charge for emissions has a larger incremental effect on emissions and a smaller incremental effect on the combined expense to companies of abating emissions and paying the amount of the charge. However, when the charge is at the higher end of the scale, the curve is relatively steep, so each successive opportunity to reduce

28. This policy design is discussed in detail in Steve Cicala, David Hémous, and Morten Olsen, *Adverse Selection as a Policy Instrument: Unraveling Climate Change*, Working Paper 30283 (National Bureau of Economic Research, July 2022), www.nber.org/papers/w30283.

29. An example of one such current effort is OGMP 2.0, a best-practices framework adopted by the Oil and Gas Methane Partnership. For more details, see United Nations Environment Programme, *Mineral Methane Initiative OGMP 2.0 Framework* (November 2020), https://tinyurl.com/yc2crac6.

emissions is much more costly than the previous one. On that part of the curve, an incremental increase in the charge does not induce companies to reduce emissions by much more. Rather, its main effect is to raise the expense associated with the charge for the remaining emissions, and that increased expense leads to higher prices of natural gas.[30] Section 60113 of the 2022 reconciliation act sets a charge of $900 per metric ton of emissions reported for 2024, $1,200 per metric ton for 2025, and $1,500 per metric ton thereafter.

The amount of time between the announcement and implementation of a charge for methane emissions affects outcomes as well. Companies are forward-looking, and their investments in new equipment can last for many years. Furthermore, it is often cheaper to reduce emissions from new sources than from old ones. Thus, the prospect of a future charge has some immediate effects on emissions, costs, and prices as new facilities are planned and developed. The full effects of a charge that is immediately implemented will be delayed because companies need time to retrofit existing facilities.

Facilities Covered by the Charge

The effects of a charge for methane emissions also depend on which facilities' emissions are subject to the charge. Section 60113 of the 2022 reconciliation act charges for methane emitted from facilities that produce oil and from those that produce, process, transmit, and store natural gas. The act exempts facilities reporting less than 25,000 CO_2-equivalent metric tons of GHG. It also exempts, in any given year, emissions from oil and natural gas wells that were permanently shut-in and plugged during the previous year.

Benchmark Emissions Rate

Whether or not emissions below a certain benchmark rate are exempted also affects how a charge for methane is analyzed. Section 60113 of the 2022 reconciliation act sets threshold emissions rates for various facilities on the basis of the amount of natural gas sent to sale: Emissions below 0.2 percent of natural gas sent to sale are exempt for facilities that produce oil and natural gas; that threshold is 0.11 percent for those that transmit natural gas and 0.05 percent for other natural gas facilities.

Such a benchmark rate effectively creates a performance standard for emissions, with the charge acting as a penalty for exceeding that standard. Companies would have no additional incentive to reduce their emissions once they reached the benchmark rate. A charge with such an exemption leads to more emissions than one without the exemption, but it also reduces companies' costs and the increase in downstream prices.

The effects of such a benchmark emissions rate depend on whether that rate is calculated on the basis of emissions from individual facilities or from the company as a whole.[31] That distinction would not matter if all emissions were subject to a charge. But when emissions below some benchmark rate are exempt, the policy's effects differ for companies operating multiple facilities if one of the following two scenarios is applicable.

First, if the cost to reduce emissions differed among facilities, a company could choose to achieve a company-level benchmark emissions rate by reducing emissions at the facilities where it was cheaper to do so. The company would thus reach that benchmark rate at a lower cost than if each of its facilities had to achieve the rate separately to avoid the charge. Therefore, in this scenario, a company-level charge would result in emissions' being reduced by the same amount but at a lower cost to the company than would a facility-level charge.

Second, if a company had one facility with an emissions rate above the benchmark and another with an emissions rate below it, and the rates of both facilities combined fell below the benchmark rate, with a facility-level charge, the company would have an incentive to reduce emissions at the high-emitting facility. But with a company-level charge, it would have no incentive to reduce emissions at either facility. Overall, compared with a facility-level charge, a company-level charge would therefore lead to less reductions of emissions, smaller cost increases, a smaller increase in downstream prices, and a smaller reduction in natural gas output.

30. The resulting price increase would induce end users to use less natural gas, so a higher charge would still create an incremental incentive to reduce methane emissions.

31. Under section 60113 of the 2022 reconciliation act, the amount of exempt emissions and the total amount of the charge for emissions are calculated at the company level.

List of Tables and Figures

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About This Document

This report, which is part of the Congressional Budget Office's continuing efforts to make its work transparent, supplies information about methane emissions from the oil and gas industry and how CBO assesses the nonbudgetary effects of imposing a charge for them. In keeping with the agency's mandate to provide objective, impartial analysis, the report makes no recommendations.

Kenneth Austin Castellanos and Evan Herrnstadt prepared the report with guidance from Nicholas Chase and Joseph Kile. David Adler, David Austin, Michael Falkenheim, Ron Gecan, Kathleen Gramp, Stephen Rabent (formerly of CBO), Janani Shankaran (formerly of CBO), Chad Shirley, and Susan Willie offered comments. Pranav Bhandarkar (formerly of CBO) fact-checked the report.

Dan Bosch of the American Action Forum, Catherine Hausman of the University of Michigan, and Levi Marks of the Department of Justice commented on an earlier draft. The assistance of external reviewers implies no responsibility for the final product; that responsibility rests solely with CBO.

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CBO seeks feedback to make its work as useful as possible. Please send comments to communications@cbo.gov.

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Director
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