Regulatory Analysis Form

(Completed by Promulgating Agency)

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INDEPENDENT REGULATORY REVIEW COMMISSION

IRRC Number: 3256

(1) Agency:

Environmental Protection

(2) Agency Number: 7

Identification Number: 544

(3) PA Code Cite: 25 Pa. Code Chapters 121 and 129

(4) Short Title: Control of VOC Emissions from Oil and Natural Gas Sources

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(6) Type of Rulemaking (check applicable box):

- ☐ Proposed Regulation
- ☒ Final Regulation
- ☐ Final Omitted Regulation
- ☐ Emergency Certification Regulation;
- ☐ Certification by the Governor
- ☐ Certification by the Attorney General

(7) Briefly explain the regulation in clear and nontechnical language. (100 words or less)

This final-form rulemaking adds reasonably available control technology (RACT) requirements and RACT emission limitations for oil and natural gas sources of volatile organic compound (VOC) emissions to Chapters 121 and 129 (relating to general provisions; and standards for sources). VOC emissions are precursors to the formation of ground-level ozone, a public health, welfare and environmental hazard. Sources affected by this final-form rulemaking include storage vessels in all segments except natural gas distribution, natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, reciprocating compressors, centrifugal compressors and fugitive emissions components. While this final-form rulemaking requires VOC emission reductions, methane emissions are also reduced as a co-benefit, because both VOCs and methane are emitted from oil and gas operations.

This final-form rulemaking will be submitted to the United States Environmental Protection Agency (EPA) for approval as a revision to the Commonwealth's State Implementation Plan (SIP) following promulgation of the final-form regulation.

(8) State the statutory authority for the regulation. Include specific statutory citation.

This final-form rulemaking is authorized under section 5(a)(1) of the Air Pollution Control Act (APCA) (35 P.S. § 4005(a)(1)), which grants the Board the authority to adopt rules and regulations for the prevention, control, reduction and abatement of air pollution in this Commonwealth. Section 5(a)(8) of the APCA (35 P.S. § 4005(a)(8)) also grants the Board the authority to adopt rules and regulations designed to implement the provisions of the Clean Air Act (CAA) (42 U.S.C.A. §§ 7401—7671q).

(9) Is the regulation mandated by any federal or state law or court order, or federal regulation? Are there any relevant state or federal court decisions? If yes, cite the specific law, case or regulation as well as any deadlines for action.

Yes, this final-form rulemaking to adopt RACT requirements and emission limitations for oil and natural gas sources of VOC emissions is required under the CAA. In accordance with sections 172(c)(1), 182(b)(2)(A) and 184(b)(1)(B) of the CAA (42 U.S.C.A. §§ 7502(c)(1), 7511a(b)(2)(A) and 7511c(b)(1)(B)), this final-form rulemaking establishes the VOC emission limitations and other RACT requirements consistent with the EPA's recommendations in the "Control Techniques Guidelines for the Oil and Natural Gas Industry," EPA 453/B-16-001, Office of Air Quality Planning and Standards, EPA, October 2016 (2016 O&G CTG) as RACT for these sources in this Commonwealth. See 81 FR 74798 (October 27, 2016).[1] This final-form rulemaking is also necessary to attain and maintain the National Ambient Air Quality Standards (NAAQS) for ozone and protect public health and welfare from harmful air pollution.

Background on the Ozone National Ambient Air Quality Standards (NAAQS)

Under section 108 of the CAA (42 U.S.C.A. § 7408), the EPA is responsible for establishing NAAQS, or maximum allowable concentrations in the ambient air, for six criteria pollutants considered harmful to public health and the environment: ground-level ozone; particulate matter; nitrogen oxides (NO_x); carbon monoxide; sulfur dioxide; and lead. Section 109 of the CAA (42 U.S.C.A. § 7409) established two types of NAAQS: primary standards, which are limits set to protect public health; and secondary standards, which are limits set to protect public welfare and the environment. In section 302(h) of the CAA (42 U.S.C.A. § 7602(h)), effects on welfare are defined to include protection against visibility impairment and from damage to animals, crops, vegetation and buildings. The EPA established primary and secondary ground-level ozone NAAQS to protect public health and public welfare, including the environment.

On April 30, 1971, the EPA promulgated primary and secondary NAAQS for photochemical oxidants, which include ground-level ozone, under section 109 of the CAA. See 36 FR 8186 (April 30, 1971). These standards were set at an hourly average of 0.08 parts per million (ppm) total photochemical oxidants not to be exceeded more than 1 hour per year. On February 8, 1979, the EPA revised the level of the primary 1-hour ozone standard from 0.08 ppm to 0.12 ppm and set the secondary standard identical to the primary standard. See 44 FR 8202 (February 8, 1979). This revised 1-hour standard was reaffirmed on March 9, 1993. See 58 FR 13008 (March 9, 1993).

On July 18, 1997, the EPA concluded that revisions to the then-current 1-hour ozone primary standard to provide increased public health protection were appropriate to protect public health with an adequate margin of safety. Further, the EPA determined that it was appropriate to establish a primary standard of 0.08 ppm averaged over 8 hours. At this time, the EPA also established a secondary standard equal to the primary standard. See 62 FR 38856 (July 18, 1997). In 2004, the EPA designated 37 counties in this Commonwealth as 8-hour ozone nonattainment areas for the 1997 8-hour ozone NAAQS. See 69 FR 23858, 23931 (April 30, 2004). Based on the Department's certified ambient air monitoring data for the Commonwealth's 2020 ozone season, all monitored areas of this Commonwealth are attaining and maintaining the 1997 8-hour ozone NAAQS.

In March 2008, the EPA lowered the primary and secondary ozone NAAQS to 0.075 ppm (75 parts per billion (ppb)) averaged over 8 hours to provide greater protection for children, other at-risk populations and

[1] See also EPA, Control Techniques Guidelines for the Oil and Natural Gas Industry, EPA 453/B-16-001, Office of Air Quality Planning and Standards, October 2016, https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf

the environment against the array of ozone-induced adverse health and welfare effects. See 73 FR 16436 (March 27, 2008). In May 2012, the EPA designated five areas in this Commonwealth as marginal nonattainment for the 2008 ozone NAAQS with the rest of this Commonwealth designated as attainment. See 77 FR 30088, 30143 (May 21, 2012). The five designated areas include all or a portion of Allegheny, Armstrong, Beaver, Berks, Bucks, Butler, Carbon, Chester, Delaware, Fayette, Lancaster, Lehigh, Montgomery, Northampton, Philadelphia, Washington and Westmoreland Counties. As with the 1997 ozone NAAQS, the Department must ensure that the 2008 ozone NAAQS is attained and maintained by implementing permanent and enforceable control measures. Based on the Department's certified ambient air monitoring data for the Commonwealth's 2020 ozone season, all monitored areas of this Commonwealth are attaining and maintaining the 2008 8-hour ozone NAAQS. Adoption of the VOC emission control measures in this final-form rulemaking would allow the Commonwealth to continue its progress in attaining and maintaining the 2008 8-hour ozone NAAQS.

On October 26, 2015, the EPA again lowered the primary and secondary ozone NAAQS, this time to 0.070 ppm (70 ppb) averaged over 8 hours. See 80 FR 65291 (October 26, 2015). On June 4, 2018, the EPA designated Bucks, Chester, Delaware, Montgomery and Philadelphia counties as marginal nonattainment for the 2015 ozone NAAQS, with the rest of this Commonwealth designated as attainment. See 83 FR 25776 (June 4, 2018). The Department must ensure that the 2015 8-hour ozone NAAQS is attained and maintained by implementing permanent and federally enforceable control measures. The certified ambient air ozone season monitoring data for the 2020 ozone season shows that all ozone samplers in this Commonwealth, except the Bristol sampler in Bucks county and the Northeast Airport and Northeast Waste samplers in Philadelphia county, are monitoring attainment of the 2015 ozone NAAQS. Reductions in VOC emissions that are achieved following the adoption and implementation of RACT emission control measures for source categories covered by this final-form rulemaking will assist the Commonwealth in making substantial progress in achieving and maintaining the 2015 ozone NAAQS.

Clean Air Act (CAA) requirements: Implementation of permanent and Federally enforceable control measures for attaining and maintaining the ozone NAAQS

Section 101(a)(3) of the CAA (42 U.S.C.A. § 7401(a)(3)) provides that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments. Section 110(a) of the CAA (42 U.S.C.A. § 7410(a)) gives states the primary responsibility for achieving the NAAQS in nonattainment areas and for maintaining the NAAQS in areas of the state that are in attainment. Section 110(a) of the CAA provides that each state shall adopt and submit to the EPA a plan (a SIP) for implementation, maintenance and enforcement of the NAAQS or a revision to the NAAQS promulgated under section 109(b) of the CAA. Additionally, section 110(a) provides that the plan shall contain adequate provisions to prevent emissions activity within a state from contributing significantly to nonattainment in, or interference with maintenance by, any other state with respect to a NAAQS. The entirety of the SIP includes the regulatory programs, actions and commitments a state will carry out to implement its responsibilities under the CAA. Once approved by the EPA and incorporated into the state's SIP, the measures of a SIP are legally enforceable under both Federal and state law.

Section 172(c)(1) of the CAA (42 U.S.C.A. § 7502(c)(1)) provides that a SIP for states with nonattainment areas must include "reasonably available control measures," including RACT, for affected sources of VOC and NO_x emissions. The EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." See 44 FR 53761 (September 17, 1979). Upon submittal to the EPA, state regulations to control VOC emissions from affected sources are reviewed by the EPA to determine if the provisions meet the RACT requirements of the CAA and its implementing regulations designed to attain and maintain the ground-level ozone NAAQS. If the EPA determines that the provisions meet the applicable requirements of the CAA, the provisions are approved and incorporated as amendments to the state's SIP.

Section 182 of the CAA (42 U.S.C.A. § 7511a) requires that, for areas which exceed the ground-level ozone NAAQS, states must develop and implement a program that mandates certain major stationary sources develop and implement a RACT emission reduction program. Section 182(b)(2) of the CAA provides that for moderate ozone nonattainment areas, a state must revise its SIP to include RACT for sources of VOC emissions covered by a CTG document issued by the EPA prior to the area's date of attainment of the applicable ozone NAAQS. CTG documents provide states with information about a VOC emission source category and recommendations of what the EPA considers to be RACT for the source category to attain and maintain the applicable ozone NAAQS. State air pollution control agencies may use the Federal recommendations provided in the CTG to inform their own determination as to what constitutes RACT for VOC emissions from the covered source category for subject sources located within the state. State air pollution control agencies may implement other technically-sound approaches that are consistent with the CAA requirements and the EPA's implementing regulations or guidelines.

Although the designated nonattainment areas in this Commonwealth for the 2008 and 2015 ground-level ozone NAAQS are classified as "marginal" nonattainment, this entire Commonwealth is treated as a "moderate" ozone nonattainment area for RACT purposes because the Commonwealth is included in the Ozone Transport Region (OTR) established by operation of law under sections 176A and 184 of the CAA (42 U.S.C.A. §§ 7506a and 7511c). Section 176A grants the Administrator of the EPA the authority to establish an interstate transport region and the associated transport commission. Section 184(a) of the CAA established the OTR comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area that includes the District of Columbia. More importantly, section 184(b)(1)(B) of the CAA requires that states in the OTR, including this Commonwealth, submit a SIP revision requiring implementation of RACT for all major stationary sources of VOC emissions in the state covered by a specific CTG and not just for those sources that are located in designated nonattainment areas of the state.

Consequently, the Commonwealth's SIP must include regulations implementing RACT requirements Statewide to control VOC emissions from the oil and natural gas sources covered by the 2016 O&G CTG. These sources, which are not regulated elsewhere in Chapter 129, were selected by the EPA because data and information has indicated that they are significant sources of VOC emissions. Significantly, this final-form rulemaking should achieve VOC emission reductions and lowered concentrations of ground-level ozone locally as well as in downwind states. Additionally, adoption of VOC emission reduction requirements is part of the Commonwealth's strategy, in concert with other OTR jurisdictions, to further reduce the transport of VOC ozone precursors and ground-level ozone throughout the OTR to attain and maintain the 8-hour ozone NAAQS. This final-form rulemaking will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation of the final-form rulemaking.

The EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry

The EPA issues guidance, in the form of a CTG, in place of regulations where the guidelines will be "substantially as effective as regulations" in reducing VOC emissions from a product or source category in ozone nonattainment areas. On October 27, 2016, the EPA issued the 2016 O&G CTG which provided information to assist states in determining what constitutes RACT for VOC emissions from select oil and natural gas industry emission sources. See 81 FR 74798. On March 9, 2018, the EPA had proposed to withdraw the 2016 O&G CTG in its entirety because the CTG had relied upon underlying data and conclusions made in the 2016 new source performance standards which the EPA was reconsidering. See 83 FR 10478 (March 9, 2018). However, on March 5, 2020, the EPA announced in the U.S. Office of Management and Budget's Spring 2020 Unified Agenda and Regulatory Plan that the EPA was no longer pursuing the action to withdraw the CTG and "the CTG will remain in place as published on October 27, 2016."[2]

While the EPA provided information and RACT recommendations through the 2016 O&G CTG for VOC emissions, it is up to the Department to determine what is RACT for each source category of VOC emissions. As mentioned by the EPA in the 2016 O&G CTG, state air pollution control agencies are free to implement other technically-sound approaches that are consistent with the CAA and the EPA's regulations. See 81 FR 74798, 74799. The EPA also further clarified that "the information contained in the CTG document is provided only as guidance" and "this guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself." *Id.* While the EPA will ultimately need to approve the Department's RACT determinations by reviewing and approving the revision to the Commonwealth's SIP, the Department has made the initial RACT determinations in this final-form rulemaking based on the entirety of information available to the Department, including the 2016 O&G CTG. In other words, the Department's obligation is to affirmatively determine what constitutes RACT for the source group identified in the 2016 O&G CTG and the EPA's provision of guidance and data in the 2016 O&G CTG does not obviate that legal requirement. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information and current emissions data specific to this Commonwealth that it analyzed to determine the RACT emission limitations and requirements established in this final-form rulemaking.

Findings of Failure to Submit, sanctions and deadline for action

If the EPA finds that a state has failed to submit an approvable SIP revision or has failed to implement the requirements of an approved measure in the SIP, the EPA issues a "finding of failure to submit notice." On November 16, 2020, the EPA issued a Final Rule entitled "Findings of Failure To Submit State Implementation Plan Revisions in Response to the 2016 Oil and Natural Gas Industry Control Techniques Guidelines for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) and for States in the Ozone Transport Region," with an effective date of December 16, 2020. 85 FR 72963 (November 16, 2020). This Commonwealth was one of the five states issued a finding of failure to submit a SIP revision addressing the RACT requirements associated with the 2016 O&G CTG by October 27, 2018. The EPA's finding triggers the sanction clock under section 179 of the CAA (42 U.S.C.A. § 7509). However, sanctions cannot be imposed until 18 months after the EPA makes the determination, and sanctions cannot be imposed if a deficiency has been corrected within the 18-month period. Thus, the Commonwealth must submit this final-form rulemaking as a SIP revision and the EPA must determine that the submittal is complete by June 16, 2022, or sanctions could take effect.

On December 16, 2021, the EPA issued a Finding of Failure to Submit SIP Revisions for the 2016 O&G CTG for the 2015 Ozone NAAQS and for states in the OTR, with an effective date of January 18, 2022. 86 FR 71385 (December 16, 2021). This finding also triggers the sanction clock under section 179 of the CAA and the Commonwealth must submit a SIP revision and the EPA must determine that the submittal is complete by July 18, 2023.

[2] See Supplemental Notice of Potential Withdrawal of the Control Techniques Guidelines for the Oil and Natural Gas Industry, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202004&RIN=2060-AT76

Section 179 of the CAA authorizes the EPA to use two types of sanctions: 1) imposing what are called “2:1 offsets” on new or modified sources of emissions; and 2) withholding of certain Federal highway funds. Under section 179 of the CAA and its implementing regulations, the Administrator first imposes “2:1 offsets” sanctions for new or modified major stationary sources in the nonattainment area, and then, if the deficiency has not been corrected within 6 months, also applies Federal highway funding sanctions. See 40 CFR 52.31 (relating to selection of sequence of mandatory sanctions for findings made pursuant to section 179 of the Clean Air Act). The Commonwealth receives Federal transportation funding annually, $1.8 billion in 2020 and 2021.

Additionally, the findings trigger an obligation under section 110(c) of the CAA for the EPA to promulgate a Federal Implementation Plan (FIP) no later than 2 years after the effective date of the finding of failure to submit if the Commonwealth has not submitted, and the EPA has not approved, the required SIP submittal. If the EPA promulgates a FIP, the EPA could, in its discretion, also withhold a portion of the Department’s air pollution grant funds provided for in section 105 of the CAA. However, if the Commonwealth makes the required SIP submittal and the EPA takes final action to approve the submittal within 2 years of the effective date of these findings, the EPA is not required to promulgate a FIP.

This final-form rulemaking will address both the December 2021 and the November 2020 findings of failure to submit SIP revisions by addressing the RACT requirements associated with the 2016 O&G CTG. This final-form rulemaking is being promulgated to attain and maintain both the 2008 and the 2015 ozone NAAQS and will be submitted to the EPA for approval as a revision to the Commonwealth's SIP following promulgation. The Department is working toward completing the submittal by June 16, 2022, to avoid any sanctions.

(10) State why the regulation is needed. Explain the compelling public interest that justifies the regulation. Describe who will benefit from the regulation. Quantify the benefits as completely as possible and approximate the number of people who will benefit.

Need for the Regulation

Beyond the legal requirements detailed in the response to Question 9, the control measures in this final-form rulemaking are needed to reduce VOC emissions from oil and natural gas sources throughout this Commonwealth. Affected sources include natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, reciprocating compressors, centrifugal compressors, fugitive emissions components, and storage vessels in all segments except natural gas distribution. Implementing VOC emission control measures consistent with the RACT recommendations of the 2016 O&G CTG for these sources will help the Commonwealth continue to maintain the 1997 and 2008 ozone NAAQS, as well as attain and maintain the 2015 ozone NAAQS. Achieving and maintaining the ground-level ozone NAAQS provides healthful air quality which attracts and retains residents and industry, supports healthy environmental conditions for agriculture and the ecosystems of this Commonwealth, and reduces transport of VOC emissions and ground-level ozone to downwind states.

VOC emissions are precursors to the formation of ground-level ozone, a public health, welfare and environmental hazard.[3, 4] Ground-level ozone is not emitted directly to the atmosphere from any sources, including oil and natural gas sources. However, ground-level ozone is formed by a photochemical reaction

[3] EPA, Ecosystem Effects of Ozone Pollution, https://www.epa.gov/ground-level ozone-pollution/ecosystem-effects-ozone-pollution

[4] EPA, Health Effects of Ozone Pollution, https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution

between emissions of VOC and NO_X in the presence of sunlight; oil and natural gas sources do emit these two pollutants. Ground-level ozone is a highly reactive gas, which at sufficiently high concentrations can produce a wide variety of effects harmful to public health and welfare and the environment. Section 302(h) of the CAA defines effects on welfare to include adverse impacts on animals, wildlife, weather, climate, visibility, crops and vegetation. Additionally, climate change may exacerbate the need to address ground-level ozone. According to the EPA, atmospheric warming, as a result of climate change, may increase ground-level ozone in regions across the United States. This impact could also be an issue for states trying to comply with future ozone standards.[5]

Ground-level ozone is a respiratory irritant and repeated exposure to high ambient concentrations of ground-level ozone pollution for both healthy people and those with existing conditions may cause a variety of adverse health effects, including difficulty in breathing, chest pains, coughing, nausea, throat irritation, and congestion. In addition, people with bronchitis, heart disease, emphysema, asthma and reduced lung capacity may have their symptoms exacerbated by high ambient concentrations of ground-level ozone pollution. Asthma, in particular, is a significant and growing threat to children and adults in this Commonwealth. Ozone can also cause both physical and economic damage to important food crops, forests, and wildlife, as well as materials such as rubber and plastics.

The implementation of additional measures to address ozone precursor emissions impacts on air quality in this Commonwealth is necessary to protect the public health and welfare and the environment. Because VOC emissions are precursors for ground-level ozone formation, adoption of the VOC emission control measures and other requirements in this final-form rulemaking is in the public interest as it will allow the Commonwealth to continue to make substantial progress in maintaining the 1997 and 2008 NAAQS as well as attaining and maintaining the 2015 8-hour ozone NAAQS Statewide. Implementation of and compliance with the final-form VOC emission reduction measures will also assist the Commonwealth in reducing the levels of ozone precursor emissions that contribute to potential nonattainment of the 2015 ozone NAAQS in downwind states. As a result, the VOC emission control measures are reasonably necessary to attain and maintain the health-based and welfare-based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements.

VOC and Methane Emission Reduction Benefits

The Department estimates that in 2020, sources in the oil and natural gas industry emitted 24,405 tons per year (TPY) VOC and that implementation of the control measures in this final-form rulemaking could reduce VOC emissions by as much as 12,068 TPY. These VOC emission reductions will contribute to reductions in the formation of ground-level ozone and to achieving and maintaining the ozone NAAQS. These reductions also contribute to the monetized public health benefits described below.

Except for storage vessels, the requirements in this final-form rulemaking serve to limit natural gas emissions without a specific VOC emission threshold, consistent with the methodology used in the 2016 O&G CTG. Because natural gas is a mixture of hydrocarbons, including methane, and other compounds there will be a significant reduction in methane emissions as a co-benefit to the required VOC emissions. Therefore, the implementation of the VOC emissions control measures in this final-form rulemaking is consistent with Governor Tom Wolf's strategy to reduce emission of methane from the oil and natural gas industry. Methane is a potent greenhouse gas with a global warming potential more than 28 times that of carbon dioxide over a 100-year time period, according to the EPA. The EPA has identified methane, the primary component of natural gas, as the second-most prevalent greenhouse gas emitted in the United States from human activities.

[5] EPA, Air Quality and Climate Change Research, https://www.epa.gov/air-research/air-quality-and-climate-change-research

The Department estimates that the oil and natural gas industry emitted 464,388 TPY methane in 2020 and that the co-benefit methane emissions reduction from this final-form rulemaking may be as much as 221,066 TPY.

Monetized public health benefits of attaining the 2015 ozone NAAQS

The EPA estimated that the monetized health benefits of attaining the 2015 8-hour ozone NAAQS of 0.070 ppm range from $1.5 billion to $4.5 billion on a National basis by 2025.[4] Prorating that benefit to this Commonwealth, based on population, results in a public health benefit of $63 million to $189 million. The Department is not stating that these estimated monetized health benefits would all be the result of implementing the RACT measures, but the EPA estimates are indicative of the benefits to Commonwealth residents of attaining the 2015 8-hour ozone NAAQS through the implementation of a suite of measures to control VOC emissions in the aggregate from different source categories.

Adverse health and welfare effects of ground-level ozone on humans, animals, and the environment

Exposure to high levels of ground-level ozone air pollution correlates to increased respiratory disease and higher mortality rates. Ozone can inflame and damage the lining of the lungs. Within a few days, the damaged cells are shed and replaced. Over a long time period, lung tissue may become permanently scarred, resulting in permanent loss of lung function and a lower quality of life. When ambient ozone levels are high, more people with asthma have attacks that require a doctor's attention or use of medication. Ozone also makes people more sensitive to allergens including pet dander, pollen and dust mites, all of which can trigger asthma attacks. The EPA has concluded that there is an association between high levels of ambient ozone and increased hospital admissions for respiratory ailments including asthma. While children, the elderly and those with respiratory problems are most at risk, even healthy individuals may experience increased respiratory ailments and other symptoms when they are exposed to high levels of ambient ozone while engaged in activities that involve physical exertion. High levels of ground-level ozone also affect animals including pets, livestock and wildlife, in ways similar to humans.

In addition to causing adverse human and animal health effects, the EPA has concluded that ground-level ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields. Ozone damage to the foliage of trees and other plants can decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of parks and recreation areas. Through deposition, ground-level ozone also contributes to pollution in the Chesapeake Bay. These effects can have adverse impacts including loss of species diversity and changes to habitat quality and water and nutrient cycles. The implementation of additional measures to address ground-level ozone air quality in this Commonwealth is necessary to protect the public health and welfare and the environment.

Adverse effects of ground-level ozone on this Commonwealth's economy

The economic value of the impacts of ground-level ozone on this Commonwealth's farm crops, fruit industries, forests, parks and timber due to high concentrations of ground-level ozone can be calculated, through things such as crop yield loss from both reduced growth and smaller, lower-quality seeds and tubers with less oil or protein. If ozone episodes last a few days, visible injury to some leaf crops, including lettuce, spinach and tobacco, as well as visible injury to the leaves of ornamental plants, including grass, flowers and shrubs, can appear. Other types of welfare loss may not be quantifiable, such as the reduced aesthetic value of trees growing in heavily visited parks.

Information about the economic benefit of the agricultural industry to this Commonwealth is provided by the Pennsylvania Department of Agriculture (PDA). In 2019, this Commonwealth had more than 53,157 farms occupying more than 7.3 million acres of farmland which account for 75,475 direct jobs and $9.0 billion in direct economic output from production agriculture. In addition to production agriculture, the industry also raises revenue and supplies jobs through support services such as food and beverage processing, marketing, transportation, farm equipment, forestry production and processing, and landscaping. In total, production agriculture and agribusiness support 232,463 direct jobs and contribute $59.7 billion to this Commonwealth's economy. The agriculture industry, including forestry, contributes 593,600 total direct, indirect, and induced jobs and $132.5 billion in total direct, indirect, and induced output.[6] Reducing ground-level ozone concentrations will serve to protect agricultural yield and reduce losses to production agriculture and agribusiness in this Commonwealth.

This Commonwealth is forested over a total of 16.6 million acres, which represents 58% of its land area. Federal, state, and local government hold 5.1 million acres in public ownership, with the remaining 11.7 million acres in private ownership.[7] The forest product industry only owns 0.4 million acres of forest, with the remainder held by an estimated 750,000 individuals, families, partnerships, or corporations.[8] This Commonwealth leads the Nation in volume of hardwood with over 120.5 billion board feet of standing sawtimber.[9] Recent data shows that the state's forest growth-to-harvest rate is better than 2 to 1.[10] As the leading producer of hardwood lumber in the United States, this Commonwealth also leads in the export of hardwood lumber, exporting nearly $463 million in 2019, and over $1.1 billion in lumber, logs, furniture and paper products to more than 70 countries around the world. Production is estimated at 1 billion board feet of lumber annually.[11] This vast renewable resource puts the hardwoods industry at the forefront of manufacturing in this Commonwealth. Forestry production and processing account for 69,437 direct jobs and $21.8 billion in direct economic output and direct value added to Pennsylvania's economy.[12] Reducing ground-level ozone concentrations will serve to protect the Commonwealth's position as the leader of growing volume of hardwood species and producer of hardwood lumber in Nation.

The Pennsylvania Department of Conservation and Natural Resources (DCNR) is the steward of the state-owned forests and parks. DCNR awards millions of dollars in construction contracts each year to build and maintain the facilities in its parks and forests. Hundreds of concessions throughout the park system help complete the park experience for both state and out-of-state visitors. State forests, parks and game lands make up 3.9 million acres of forest land. This Commonwealth's 2.2 million-acre state forest system, found in 48 of this Commonwealth's 67 counties, comprises 13% of the forested area in the Commonwealth.[13] The state forest represents one of the largest expanses of public forestland in the eastern United States, making it a priceless public asset. Ozone damage to the foliage of trees and other plants can decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of parks and recreation

[6] PDA, Pennsylvania Agriculture: A look at the Economic Impact and Future Trends Version 1, Jan. 2018, https://www.agriculture.pa.gov/Documents/PennsylvaniaAgriculture_EconomicImpactFutureTrends.pdf
[7] United States Department of Agriculture, Forests of Pennsylvania, 2019, https://public.tableau.com/views/FIA_OneClick_V1_2/Factsheet?%3AshowVizHome=no
[8] The Pennsylvania State University, Forest Management and Timber Harvesting in Pennsylvania, Sept. 9, 2019, https://extension.psu.edu/forest-management-and-timber-harvesting-in-pennsylvania
[9] *Id.*
[10] United States Department of Agriculture, Forests of Pennsylvania, 2019, https://public.tableau.com/views/FIA_OneClick_V1_2/Factsheet?%3AshowVizHome=no
[11] PDA, Response to Email Inquiry, Harrisburg, Pennsylvania, Mar. 2, 2020, available on request.
[12] PDA, Pennsylvania Agriculture: A look at the Economic Impact and Future Trends Version 1, Jan. 2018, https://www.agriculture.pa.gov/Documents/PennsylvaniaAgriculture_EconomicImpactFutureTrends.pdf
[13] Pennsylvania DCNR Bureau of Forestry, Our Mission and What We Do, https://www.dcnr.pa.gov/about/Pages/Forestry.aspx

areas. However, the effects of the reduced aesthetic value of trees in heavily visited parks may not be quantifiable. Reducing the concentration of ground-level ozone will help maintain the benefits to this Commonwealth's economy due to tourism.

In sum, adoption and implementation of the VOC emission control measures in this final-form rulemaking for the owners or operators of certain sources in the oil and natural gas industry is reasonably necessary to allow the Commonwealth to continue its progress in attaining and maintaining the public health-based and welfare-based 8-hour ozone NAAQS and to satisfy related CAA requirements. The VOC emission reductions achieved through implementation of the regulatory requirements established in this final-form rulemaking and the associated decrease in formation of ground-level ozone will benefit the health and welfare of the residents of this Commonwealth as well as the health of tourists and visitors, with improved ambient air quality and healthier environments. The decrease in ground-level ozone formation will also benefit farmers, loggers, hunters and outdoor enthusiasts and the numerous animals, crops, vegetation and natural areas of this Commonwealth. The agriculture and timber industries and related businesses will benefit directly from reduced economic losses that result from ozone damage to crops and timber. Likewise, the natural areas and infrastructure within this Commonwealth and downwind states will benefit directly from reduced environmental damage and economic losses due to ground-level ozone.

(11) Are there any provisions that are more stringent than federal standards? If yes, identify the specific provisions and the compelling Pennsylvania interest that demands stronger regulations.

Yes, some provisions of this final-form rulemaking are more stringent than Federal standards. Under Section 4.2(b)(1) of the APCA (35 P.S. § 4004.2(b)(1)), the Board has the authority to adopt control measures that are more stringent than those required by the CAA if the Board determines that it is reasonably necessary for the control measure to exceed minimum CAA requirements for the Commonwealth to achieve or maintain the NAAQS. To the extent that a requirement in this final-form rulemaking is more stringent than the recommendations of the 2016 O&G CTG, the more stringent requirement is reasonably necessary to attain and maintain the health-based and welfare based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements.

The control requirements for storage vessels, reciprocating compressors and fugitive emissions components in this final-form rulemaking are more stringent than the recommendations of the 2016 O&G CTG. Based on comments received, the Department performed an updated cost/benefit analysis (2020 reanalysis) which shows that the more stringent standards in this final-form rulemaking are RACT, meaning they are technically and economically feasible. As discussed previously, the Department is obligated to determine what control standards are RACT for sources of VOC emissions in this Commonwealth. In the 2016 O&G CTG,[14] the EPA provided RACT recommendations based on the information reviewed by the EPA at the time. However, as explicitly stated by the EPA in the 2016 O&G CTG, state air pollution control agencies are free to implement other technically-sound approaches that are consistent with the CAA and the EPA's regulations. See 81 FR 74798, 74799. The EPA also further clarified that "the information contained in the CTG document is provided only as guidance" and "this guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself." *Id.*

[14] See EPA, Control Techniques Guidelines for the Oil and Natural Gas Industry, EPA 453/B-16-001, Office of Air Quality Planning and Standards, October 2016, https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf, for a detailed description of the sources, VOC emissions, RACT recommendations, available VOC emission control technologies, and costs.

While the EPA will ultimately need to approve the Department's RACT determinations by reviewing and approving the revision to the Commonwealth's SIP, the Department has made the RACT determinations in this final-form rulemaking based on the entirety of information available to the Department, including the 2016 O&G CTG. In the time since the 2016 O&G CTG was issued by the EPA, the Department acquired additional information and current emissions data specific to this Commonwealth that it analyzed to determine the RACT emission limitations and requirements established in this final-form rulemaking. Additionally, due to this Commonwealth's status as a member of the OTR and the 2015 ozone nonattainment areas, the VOC emission reductions achieved by this final-form rulemaking are necessary to attain and maintain compliance with the ozone NAAQS and to fulfill the Commonwealth's obligation under Section 184 of the CAA.

Furthermore, based on analysis of data available to the Department during the development of the proposed rulemaking as well as additional and updated data available during the final-form rulemaking development phase, the Department determined in three cases that RACT requirements more stringent than the recommendations in the 2016 O&G CTG are cost-effective and necessary to continue the Commonwealth's progress in attaining and maintaining the ground-level ozone NAAQS.

To determine whether a specific air pollution control technology is an economically feasible option to be considered as RACT, the Department has used a cost-effectiveness benchmark in terms of annualized costs per ton of VOC emissions removed. The Department adjusted cost benchmarks established in previous RACT rulemakings of $5,500 per ton of VOC emissions removed, by multiplying by the Consumer Price Index differential between 2014 and 2021 to arrive at a benchmark of $6,600 per ton of VOC emissions removed.

Storage vessels

In the first case, the Department established in proposed § 129.123(a)(1)(i)—(vi) (relating to storage vessels) a tiered emissions threshold based on the potential to emit for the affected owners or operators of subject storage vessels to prevent backsliding on the amount of controlled emissions for storage vessels subject to the Department's Air Quality Permit Exemptions 38(b) or 38(c). The tiered emission threshold established in proposed § 129.123(a)(1)(i) and (ii) was the potential to emit 6.0 TPY or greater VOC emissions for a storage vessel installed at a conventional well site or at an unconventional well site before August 10, 2013. The tiered emission threshold established in proposed § 129.123(a)(1)(iii)—(vi) was the potential to emit 2.7 TPY or greater VOC emissions for a storage vessel installed at an unconventional well site on or after August 10, 2013, a storage vessel installed at a gathering and boosting station, a storage vessel installed at a natural gas processing plant and a storage vessel installed at a facility in the natural gas transmission and storage segment.

However, during the development of this final-form rulemaking, the Department performed additional analysis which shows that the 2.7 TPY VOC emission threshold for storage vessels is RACT as it is technically and economically feasible for both potential to emit and actual emissions from all covered storage vessels at both conventional and unconventional well sites. The analysis examined the sensitivity to the initial capital cost of the control device and found that the total cost per ton of VOC reduced is below the RACT benchmark of $6,600/ton reduced. Therefore, a single 2.7 TPY VOC emission threshold is established in § 129.123(a)(1) in this final-form rulemaking that applies to affected owners or operators of storage vessels in all segments except natural gas distribution. The tiered emissions thresholds in proposed § 129.123(a)(1)(i)—(vi) are deleted in this final-form rulemaking.

Reciprocating compressor rod packing replacements

In the second case, the proposed rulemaking included an exemption in § 129.126(d) for the owner or operator of a reciprocating compressor or a centrifugal compressor located at a well site or located at an adjacent well site and servicing more than one well site. However, the Department's additional analysis for this final-form rulemaking shows that it is both technically and economically feasible to require reciprocating compressor rod packing replacements every 26,000 hours of operation or every three years, at the operator's discretion, for reciprocating compressors located at well sites. The analysis showed that the cost-effectiveness of the rod packing replacement is highly sensitive to the emissions factor used to represent emissions from reciprocating compressors. Using the average of several emission factors from the University of Texas at Austin's Emission Factor Improvement Study,[15] the cost per ton of VOC reduced is approximately $6,600 which is consistent with the RACT benchmark. Therefore, the exemption in proposed § 129.126(d) for reciprocating compressors is deleted in this final-form rulemaking, meaning this final-form rulemaking requires affected owners or operators to implement reciprocating compressor rod packing replacements on reciprocating compressors located at well sites. This is a new requirement that was not included in the proposed rulemaking and was not one of the recommendations in the 2016 O&G CTG.

Fugitive emissions components

In the third case, the Department established a requirement in proposed § 129.127(b)(1)(ii)(A) and (B) (relating to fugitive emissions components) that affected owners or operators shall conduct monthly audible, visual, and olfactory (AVO) inspections and quarterly instrument-based leak detection and repair (LDAR) inspections of fugitive emissions components for well sites with at least one well that produces, on average, 15 barrels of oil equivalent (BOE) per day. In proposed § 129.127(b)(2), the Department also established a stepdown provision which enabled affected owners or operators to track the percentage of leaking components at each inspection and if, in two consecutive quarterly inspections, less than 2% of components were leaking emissions, the owner or operator could reduce the quarterly schedule of instrument-based LDAR inspections to semiannual.

This final-form rulemaking deletes the stepdown provisions of proposed § 129.127(b)(2)(i) and (ii). The Department's additional analysis shows that it is both technically and economically feasible for an affected owner or operator to implement instrument-based LDAR inspections at a well site with an average production of 15 BOE or more per day, with the frequency of inspections based on the production from each individual well at the well site. The owner or operator of a well site with an average production of 15 BOE or more per day and with at least one individual well producing 15 BOE or more per day, on average, shall conduct quarterly instrument-based LDAR inspections. The owner or operator of a well site with an average of 15 BOE or more per day and at least one individual well producing 5 BOE or more but less than 15 BOE per day, on average, shall conduct annual instrument-based LDAR inspections. In this final-form rulemaking the Department also included an option for the owner or operator of a well site producing, on average, equal to or greater than 15 BOE per day, and at least one well producing, on average, equal to or greater than 5 BOE per day but less than 15 BOE per day to submit to the Department a request for an exemption from the annual instrument-based LDAR requirement. However, the request must include, among other information, a demonstration that the annual LDAR requirement is not RACT (technically or economically feasible) for the well site.

Reasonable and necessary to implement more stringent than EPA RACT recommendations

In addition to the technically and economically feasible RACT requirements detailed above, the Commonwealth is responsible for ensuring that the 2015 8-hour ozone NAAQS is attained and maintained by implementing permanent and Federally enforceable control measures. This final-form rulemaking is a primary component of the Commonwealth's strategy of ensuring that the ozone NAAQS are attained and maintained across this Commonwealth. Reductions in VOC emissions that are achieved following the adoption and implementation of RACT VOC emission control measures for the select oil and natural gas source categories covered by this final-form rulemaking will assist the Commonwealth in making substantial progress in achieving and maintaining the ozone NAAQS. To the extent that a requirement in this final-form rulemaking is more stringent than the recommendations of the 2016 O&G CTG, the more stringent requirement is reasonably necessary to attain and maintain the health-based and welfare based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements.

(12) How does this regulation compare with those of the other states? How will this affect Pennsylvania's ability to compete with other states?

The 2016 O&G CTG applies to affected sources in designated areas of nonattainment and the states and jurisdictions included in the OTR established by operation of law under the CAA. The Department contacted representatives from Maryland, New York, Ohio, Texas and West Virginia; all stated that they do not have affected sources. The remaining states in the OTR (Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, Rhode Island and Vermont, as well as the District of Columbia) also do not have affected sources.

Several states regulate VOC emissions from storage vessels used in the oil and natural gas industry. There are also a few states (e.g., California, Colorado and Montana) that have established specific regulations that control VOC emissions from emission sources in the oil and natural gas industry (e.g., compressors, pneumatic controllers and fugitive emission components).

CALIFORNIA AIR RESOURCES BOARD

The California Air Resources Board (CARB) has a statewide methane rule for sources in the oil and gas industry, entitled *Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities*.[16]

For storage vessels, the CARB rule requires separators and tank systems not controlled by a vapor collection system to conduct a flash analysis. If the annual emission rate is greater than 10 metric tons of methane, emissions must be controlled by a vapor collection system. If the annual emission rate is less than 10 metric tons, the owner or operator must conduct an annual flash analysis for 3 years; if the annual emission rate is consistently less than 10 metric tons, reduce testing to once every 5 years. For circulation tanks used for well stimulation treatments, owners or operators must implement best practices to reduce emissions.

For natural gas-driven pneumatic controllers, the CARB rule requires that continuous bleed controllers shall not vent to the atmosphere and that each device must be inspected during each LDAR inspection. Continuous bleed controllers installed prior to January 1, 2016 may be used, provided they have a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh); are tested annually using a direct measurement method; those with a bleed rate of greater than 6 scfh must be repaired within 14 calendar days. Each device that must be replaced or retrofitted to comply shall either be controlled by a vapor collection system or be

[15] Harrison, M., Galloway, K., Hendler, A., Shires, T., Allen, D., Foss, M., Thomas, J., Spinhirne, J., Natural Gas Industry Methane Emission Factor Improvement Study Final Report Cooperative Agreement No. XA-83376101, Dec. 2011, https://dept.ceer.utexas.edu/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf

[16] See 17 CCR §§ 95665—95677, https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf

replaced with compressed air or an electricity driven controller. Intermittent bleed controllers must be inspected during each LDAR inspection while the device is idle and not controlling.

For natural gas-driven diaphragm pumps, the CARB rule requires that pumps shall not vent to the atmosphere and that each pump must be inspected during each LDAR inspection. Each device that must be replaced or retrofitted to comply shall either be controlled by a vapor collection system or be replaced with compressed air or an electricity driven pump.

For reciprocating compressors at production facilities, the CARB rule requires rod packings or seals be inspected during each LDAR inspection and repaired within 30 days of detection. For reciprocating compressors at natural gas gathering and boosting stations, processing plants, transmission stations, and underground storage facilities, the CARB rule requires rod packings or seals be inspected during each LDAR inspection; the rod packing or seal emission rate be tested annually using a direct measurement method; those with a rod packing or seal emission rate greater than 2 standard cubic feet per minute (scfm), or a combined emission rate greater than the number of compression cylinders multiplied by 2 scfm must be repaired within 30 calendar days. Alternatively, emissions shall be controlled by a vapor collection system.

For wet seal centrifugal compressors, the CARB rule requires components on driver engines and compressors be inspected during each LDAR inspection; the wet seal emission flow rate be tested annually using a direct measurement method; those with a wet seal emission flow rate greater than 3 scfm, or a combined wet seal emission rate greater than the number of wet seals multiplied by 3 scfm must be repaired within 30 days of detection. If no parts are available to make repairs, the wet seal must be replaced with a dry seal no later than January 1, 2020. Alternatively, emissions shall be controlled by a vapor collection system.

For dry seal centrifugal compressors, the CARB rule requires components on driver engines and compressors be inspected during each LDAR inspection.

For fugitive emissions components, the CARB rule requires quarterly inspections with at least one quarterly inspection performed using EPA Method 21, 40 CFR Part 60, Appendix A-7 (relating to test methods 19 through 25E), regarding determination of VOC leaks (Method 21). Optical Gas Imaging (OGI) may be used for the remaining inspections, however any leak detected must be measured within 2 calendar days using Method 21. For unsafe or inaccessible components, the CARB rule requires annual inspection using Method 21. If additional inspections are performed using OGI, any detected leak must be measured within 14 calendar days using Method 21. A facility with less than or equal to 200 components may have 5 leaks greater than or equal to 1,000 ppm and less than or equal to 9,999 ppm which must be repaired within 14 calendar days unless it is a critical component. A facility with less than or equal to 200 components may have 2 leaks greater than or equal to 10,000 ppm and less than or equal to 49,999 ppm which must be repaired within 5 calendar days unless it is a critical component. A facility with greater than 200 components may have 2% of inspected components with leaks greater than or equal to 1,000 ppm and less than or equal to 9,999 ppm which must be repaired within 14 calendar days unless it is a critical component. A facility with greater than 200 components may have 1% of inspected components with leaks greater than or equal to 10,000 ppm and less than or equal to 49,999 ppm which must be repaired within 5 calendar days unless it is a critical component. There are no allowable leaks with a detected leak greater than or equal to 50,000 ppm; the leak must be repaired within 2 calendar days unless it is a critical component.

For facilities visited daily, daily AVO inspections of hatches, pressure-relief valves, well casings, stuffing boxes and pump seals are required. For facilities not visited daily, weekly AVO inspections of hatches, pressure-relief valves, well casings, stuffing boxes and pump seals are required. Annual AVO inspections must be completed of all pipes. Any leak detected during an AVO inspection and not repaired within 24 hours of detection must be measured using Method 21.

For fugitive emissions components, the CARB rule requires that components that incur 5 repair actions in a year must be replaced with a compliant component and reinspected using Method 21.

For fugitive emissions components, the CARB rule allows delay of repair for parts on order not to exceed 30 calendar days unless approved by the Executive Officer. If a gas service utility provides documentation that the system is temporarily classified as critical to reliable public gas system operation or if the owner or operator demonstrates the component is a critical component, the repair must be completed by the end of the next process shutdown or within 12 months, whichever is sooner.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

The South Coast Air Quality Management District (SCAQMD) has Rule 463[17] for organic liquid storage and Rule 1173[18] for control of VOC leaks and releases from components at petroleum facilities and chemical plants.

For storage vessels, the SCAQMD rule requires storage vessels with a capacity greater than or equal to 19,815 gallons and containing an organic liquid with a true vapor pressure (TVP) greater than or equal to 1.5 pounds per square inch absolute (psia) under actual storage conditions or with a capacity greater than or equal to 39,630 gallons and containing an organic liquid with a TVP greater than or equal to 0.5 psia under actual storage conditions to control using either an external floating roof; internal floating-type cover; vapor recovery system that routes emissions to a fuel gas system or reduces emissions by 95% by weight when compared to a fixed cone roof tank holding the same liquid without control or vapor recovery system; or other approved equivalent control.

For fugitive emissions components, the SCAQMD rule requires quarterly inspection of all accessible components in light liquid/gas/vapor service and pumps in heavy liquid service using Method 21. For inaccessible components in light liquid/gas/vapor service, annual inspection using Method 21 is required. For pressure-relief devices that vent to the atmosphere, inspection within 1 calendar day and reinspection within 14 calendar days after every release are required.

For pumps, compressors and atmospheric pressure-relief devices, the SCAQMD rule requires AVO inspection every 8 hours unless the source is located at an unmanned production field or pipeline transfer station.

For fugitive emissions components, the SCAQMD rule defines a major leak in light liquid/gas/vapor service as greater than 10,000 ppm for valves, pumps, compressors, threaded connections, or other components; as greater than 200 ppm for pressure-relief devices; as a light liquid leak greater than 3 drops per minute. A minor leak in light liquid/gas/vapor service is defined as greater than or equal to 500 ppm and less than or equal to 10,000 ppm for valves, pumps, compressors, threaded connections or other components. A major leak in heavy liquid service is defined as greater than 500 ppm for valves, compressors, threaded connectors or other components; as greater than 100 ppm for pumps; as greater than 200 ppm for pressure-relief devices; as a heavy liquid leak greater than 3 drops per minute. A minor leak in heavy liquid service is defined as

[17] SCAQMD, Organic Liquid Storage, Rule 463, November 4, 2011, https://ww3.arb.ca.gov/drdb/sc/curhtml/r463.pdf

[18] SCAQMD, Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants, Rule 1173, February 6, 2009, https://ww3.arb.ca.gov/drdb/sc/curhtml/r1173.pdf

greater than or equal to 100 ppm and less than 500 ppm for valves, compressors, threaded connections or other components. For facilities with less than or equal to 200 components, valves, compressors, pressure-relief devices, threaded connections and other components, the sources are allowed to have 1 leak; pumps are allowed to have 2 leaks. For facilities with greater than 200 components, valves and threaded connectors are allowed to have leaks equal to 0.5% of total components inspected; pumps are allowed to have leaks equal to 1% of total components inspected; compressors, pressure-relief devices, and other components are allowed to have 1 leak.

For fugitive emissions components, the SCAQMD rule requires that minor leaks for components in light liquid/gas/vapor service and heavy liquid service be repaired within 7 calendar days with an additional 7 calendar days extended repair period. A heavy liquid leak with greater than 3 drops per minute and a minor leak by concentration have a repair period of 7 calendar days with no extended repair period. A major leak greater than 25,000 ppm has a repair period of 2 calendar days with an additional 3 calendar days extended repair period. A major leak greater than or equal to 25,000 ppm has a repair period of 1 calendar day with no extended repair period. A major leak for a component in heavy liquid service has a repair period of 1 calendar day with no extended repair period. A light liquid leak greater than 3 drops per minute has a repair period of 1 calendar day with no extended repair period. The extended repair period can be used for a total number of leaking components not to exceed 0.05% of the number of components inspected, by type, rounded to the nearest integer.

For fugitive emissions components, the SCAQMD rule requires that components that incur five repair actions in a year must be replaced or retrofitted with an applicable technology, replaced with a best available control technology (BACT) equipment, or vented to an air pollution control device approved by the Executive Officer of the SCAQMD.

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

The San Joaquin Valley Air Pollution Control District (SJVAPCD) has Rule 4409[19] for components at light crude oil production facilities, natural gas production facilities, and natural gas processing facilities and Rule 4623[20] for storage of organic liquids.

For storage vessels, the SJVAPCD rule requires storage vessels with a capacity greater than or equal to 1,100 gallons and less than or equal to 19,800 gallons and a TVP greater than or equal to 0.5 psia and less than 11 psia to control using either a pressure-vacuum relief valve, internal floating roof, external floating roof or vapor recovery system and with a TVP greater than or equal to 11 psia to control using a pressure vessel or vapor recovery system. The rule requires storage vessels with a capacity greater than 19,800 gallons and less than or equal to 39,600 gallons and a TVP greater than or equal to 0.5 psia and less than 1.5 psia to control using either a pressure-vacuum relief valve, internal floating roof, external floating roof or vapor recovery system; with a TVP greater than or equal to 1.5 psia and less than 11 psia to control using either an internal floating roof, external floating roof or vapor recovery system; and with a TVP greater than or equal to 11 psia to control using a pressure vessel or vapor recovery system. The rule requires storage vessels with a capacity greater than 39,600 gallons and a TVP greater than or equal to 0.5 psia and less than 11 psia to control using either an internal floating roof, external floating roof or vapor recovery system and with a TVP greater than or equal to 11 psia to control using a pressure vessel or vapor recovery system. There are also different requirements for small producers based on their crude oil throughput.

[19] SJVAPCD, Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities, Rule 4409, April 20, 2005, https://ww3.arb.ca.gov/drdb/sju/curhtml/r4409.pdf
[20] SJVAPCD, Storage of Organic Liquids, Rule 4623, May 19, 2005, https://ww3.arb.ca.gov/drdb/sju/curhtml/r4623.pdf

For fugitive emissions components, the SJVAPCD rule requires quarterly inspection of all accessible components using Method 21. For unsafe or inaccessible components, inspection must occur annually using Method 21. Frequency may be reduced to annually for components, except for pumps, compressors, and pressure-relief devices, provided there is not a violation during five consecutive quarterly inspections, the operator did not receive a notice of violation during the previous 12 months, and the reduction in frequency is requested in writing with the documentation to demonstrate these requirements have been met.

For facilities visited daily, daily AVO inspections of operating pumps, compressors, and pressure-relief valves. For facilities not visited daily, weekly AVO inspections are required of operating pumps, compressors, and pressure-relief valves. Annual AVO inspections are required of all pipes. Any leak detected during an AVO inspection not repaired within 24 hours of detection must be measured using Method 21.

For fugitive emissions components, the SJVAPCD rule defines a major leak as greater than 10,000 ppm for all components. A minor leak in light liquid service is defined as greater than or equal to 1,000 ppm and less than or equal to 10,000 ppm for all components other than pressure-relief devices; for a pressure-relief device a leak in light liquid service is defined as greater than or equal to 200 ppm and less than or equal to 10,000 ppm. A minor leak in gas/vapor service is defined as greater than or equal to 2,000 ppm and less than or equal to 10,000 ppm for all components other than pressure-relief devices; for a pressure-relief device a leak in gas/vapor service is defined as greater than or equal to 400 ppm and less than or equal to 10,000 ppm. For facilities with less than or equal to 200 components, valves, threaded connections, flanges, compressors, pressure-relief devices and other components are allowed to have 1 leak; pumps, pipes at production facilities, and pipes at natural gas processing facilities are allowed to have 2 leaks; polished rod stuffing boxes are allowed to have 4 leaks. For facilities with greater than 200 components, valves, threaded connectors, and flanges are allowed to have leaks equal to 0.5% of total components inspected; pumps and pipes at production facilities are allowed to have leaks equal to 1% of total components inspected; compressors, pressure-relief devices, and other components are allowed to have 1 leak; pipes at natural gas processing facilities are allowed to have 2 leaks; polished rod stuffing boxes are allowed to have leaks equal to 2% of total components inspected.

For fugitive emissions components, the SJVAPCD rule allows minor leaks 7 calendar days for repair with an additional 7 calendar days extended repair period unless it is a critical component. A major leak less than or equal to 50,000 ppm has a repair period of 5 calendar days with an additional 2 calendar days extended repair period unless it is a critical component. A major leak greater than 50,000 ppm has a repair period of 2 calendar day with no extended repair period unless it is a critical component. The extended repair period can be used for a total number of leaking components not to exceed 0.05% of the number of components inspected, by type, rounded to the nearest integer.

For fugitive emissions components, the SJVAPCD rule requires that components that incur five repair actions in a year must be replaced or retrofitted with an applicable technology, replaced with a BACT equipment meeting Rule 2201,[21] vented to a closed vent system, or removed from operation. A critical component must be repaired by the end of the next process shutdown or within 12 months, whichever is sooner.

[21] SJVAPCD, New and Modified Stationary Source Review Rule, Rule 2201, April 21, 2011, https://ww3.arb.ca.gov/drdb/sju/curhtml/r2201.pdf

COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

The Colorado Department of Public Health and Environment, Air Quality Control Commission developed a regulation applicable to oil and natural gas industry emission sources covered by the 2016 O&G CTG, entitled *Regulation Number 7 Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (emissions of volatile organic compounds and nitrogen oxides)*. See 5 CCR § 1001-9.

At production facilities in ozone nonattainment areas

Condensate storage tanks with actual uncontrolled VOC emissions greater than or equal to 2 TPY require 90% reduction on a calendar weekly basis from May 1 through September 30 and require 70% reduction on a calendar monthly basis from October 1 through April 30.

Natural gas-driven pneumatic controllers are required to be replaced or retrofitted such that emissions are reduced to less than or equal to 6 scfh unless a higher bleed rate is required for safety or process purposes.

Natural gas-driven diaphragm pump emissions are required to be routed to a control device or process unless technically infeasible. VOC emissions must be reduced by 95% or the highest destruction efficiency the control can achieve.

Fugitive emissions components require annual LDAR for facilities emitting greater than 1 TPY VOC and less than or equal to 6 TPY VOC and semiannual LDAR for facilities emitting greater than 6 TPY VOC. LDAR can be with Forward-Looking Infrared (FLIR) imaging, with a leak definition of any visible emission, or Method 21 with a leak definition of 500 ppm as methane. Leaking components must have a first attempt to repair within 5 calendar days, with repair completed no later than 30 calendar days unless delay of repair is necessary. Repairs must be remonitored within 15 calendar days. Delay of repair is allowed for ordering parts required for repair, which must be completed within 15 calendar days of receipt of parts or if a shutdown is required for repair, which must be completed at the next scheduled shutdown but no later than 2 years.

At compressor stations and processing plants in ozone nonattainment areas

Storage vessels with actual uncontrolled VOC emissions greater than or equal to 2 TPY require 95% reduction on a 12-month rolling basis.

Natural gas-driven pneumatic controllers at compressor stations are required to be replaced or retrofitted such that emissions are reduced to less than or equal to 6 scfh unless a higher bleed rate is required for safety or process purposes. Natural gas-driven pneumatic controllers at processing plants are required to have a bleed rate of zero unless required for safety or process purposes.

Natural gas-driven diaphragm pumps at processing plants are required to have zero emissions.

Reciprocating compressor rod end packings are required to be replaced every 26,000 hours of operation or every 36 months. Alternatively, emissions from the rod end packing can be routed to a process through a closed vent system.

Centrifugal compressor wet seal degassing system emissions are required to be routed to a control device achieving 95% destruction efficiency through a closed vent system.

Fugitive emissions components require quarterly LDAR at compressor stations. LDAR can be with FLIR imaging, with a leak definition of any visible emission, or Method 21 with a leak definition of 500 ppm as methane. Leaking components must have a first attempt to repair within 5 calendar days, with repair completed no later than 30 calendar days unless delay of repair is necessary. Repairs must be remonitored within 15 calendar days. Delay of repair is allowed for ordering parts required for repair, which must be completed within 15 calendar days of receipt of parts or if a shutdown is required for repair, which must be completed at the next scheduled shutdown but no later than 2 years.

Fugitive emission components at processing plants require LDAR in accordance with 40 CFR Part 60, Subpart OOOOa (relating to standards of performance for crude oil and natural gas facilities for which construction, modification or reconstruction commenced after September 18, 2015), if applicable; otherwise, in accordance with 40 CFR Part 60, Subpart OOOO (relating to standards of performance for crude oil and natural gas facilities for which construction, modification, or reconstruction commenced after August 23, 2011, and on or before September 18, 2015) regardless of construction date.

At oil and gas facilities across the state

Condensate storage vessels with actual uncontrolled VOC emissions greater than or equal to 20 TPY require 95% reduction on a 12-month rolling basis. Other storage vessels with actual uncontrolled VOC emissions greater than or equal to 6 TPY require 95% reduction on a 12-month rolling basis unless a combustion control device authorized on or after May 1, 2014 is used in which case it must have a design 98% destruction efficiency.

Natural gas-driven pneumatic controllers at production facilities and compressor stations are required to be replaced or retrofitted such that emissions are reduced to less than or equal to 6 scfh unless a higher bleed rate is required for safety or process purposes. Natural gas-driven pneumatic controllers at processing plants are required to have a bleed rate of zero unless required for safety or process purposes.

Fugitive emissions components require one time only LDAR and monthly AVO inspections for production facilities emitting greater than 0 TPY VOC and less than or equal to 6 TPY VOC; annual LDAR and monthly AVO inspections for production facilities emitting greater than 6 TPY VOC and less than or equal to 12 TPY VOC; quarterly LDAR and monthly AVO inspections for production facilities with storage vessels emitting greater than 12 TPY VOC and less than or equal to 50 TPY VOC and for production facilities without storage vessels emitting greater than 12 TPY VOC and less than or equal to 20 TPY VOC; and monthly LDAR for production facilities with storage vessels emitting greater than 50 TPY VOC and for production facilities without storage vessels emitting greater than 20 TPY VOC. LDAR can be with FLIR imaging, with a leak definition of any visible emission, or Method 21 with a leak definition of 500 ppm as methane. Leaking components must have a first attempt to repair within 5 calendar days, with repair completed no later than 30 calendar days unless delay of repair is necessary. Repairs must be remonitored within 15 calendar days. Delay of repair allowed for order of parts required for repair, which must be completed within 15 calendar days of receipt of parts or if a shutdown is required for repair, which must be completed at the next scheduled shutdown but no later than 2 years.

Fugitive emissions components require annual LDAR for compressor stations emitting greater than 0 TPY VOC and less than or equal to 12 TPY VOC; quarterly for compressor stations emitting greater than 12 TPY VOC and less than or equal to 50 TPY VOC; and monthly for compressor stations emitting greater than 50 TPY VOC. LDAR can be with FLIR imaging, with a leak definition of any visible emission, or Method 21 with a leak definition of 2,000 ppm as methane for compressor stations constructed prior to May 1, 2014 and a leak definition of 500 ppm as methane for compressor stations constructed on or after May 1, 2014.

Leaking components must have a first attempt to repair within 5 calendar days, with repair completed no later than 30 calendar days unless delay of repair is necessary. Repairs must be remonitored within 15 calendar days. Delay of repair is allowed for ordering of parts required for repair, which must be completed within 15 calendar days of receipt of parts or if a shutdown is required for repair, which must be completed at the next scheduled shutdown but no later than 2 years.

MARYLAND DEPARTMENT OF THE ENVIRONMENT

The Maryland Department of the Environment (MDE) submitted a negative declaration[22] for the 2016 O&G CTG to the EPA on June 11, 2020.

MDE is also proposing to create a methane rule[23] in two phases for the control of sources in the oil and natural gas industry. The first phase is for an LNG facility and 4 natural gas compression facilities which have the following proposed requirements:

For natural gas-driven pneumatic controllers, the bleed rate cannot exceed 6 scfh whether they are continuous or intermittent bleed. Beginning January 1, 2022, continuous bleed controllers must be powered by compressed air or electricity unless they were installed prior to January 1, 2021 and use a vapor collection system or receive approval from MDE.

For reciprocating compressors, the rod packing flow rate must be measured annually and repaired if the flow rate exceeds 1 scfm or the combined flow rate equal to the number of cylinders times 1 scfm. Alternatively, emissions can be routed to a vapor collection system.

For fugitive emissions components, quarterly LDAR inspections using OGI or Method 21 are proposed. Repairs must be made and certified within 30 calendar days. Delay of repair is authorized for ordering parts, with repair completed within 7 calendar days of receipt of parts; if repair is infeasible, requires a vent or compressor station blowdown or is unsafe to repair during operation, repair must be completed during the next planned shutdown or vent blowdown.

There is a forthcoming proposed methane rule for the natural gas distribution system as part of phase one.

The second phase is the production sector; however, Maryland only has 10 active wells and has had a hydraulic fracturing ban in place since 2017.

MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY

The Montana Department of Environmental Quality requires oil and gas well facilities to control emissions from the time the well is completed until the source is registered or permitted. Subchapter 16 implements emission control requirements for oil and gas well facilities operating prior to the issuance of a Montana Air Quality Permit. See ARM 17.8.1601—1606. Subchapter 17 implements the registration of air contaminant sources. See ARM 17.8.1701—1713.

[22] MDE, Maryland Negative Declaration for Control Techniques Guidelines (CTG) for the Oil and Natural Gas Industry (EPA-453/B-16-001 – October 2016), June 11, 2020, https://mde.maryland.gov/programs/Air/AirQualityPlanning/Documents/CTGs/20-07_CTG_Oil_Gas_Negative_Declaration.pdf

[23] MDE, Chapter 41 Control of Methane Emissions from the Natural Gas Industry, Oct. 11, 2019, https://mde.maryland.gov/programs/Regulations/air/Documents/SHMeetings/NaturalGasCompressors/26.11.41DiscussionDraft10112019.pdf

For storage vessels with a PTE greater than or equal to 15 TPY VOC and vapors of 500 Btu/scf in subchapter 16 or 200 Btu/scf in subchapter 17, emissions must be captured and routed to a gas pipeline, routed to a smokeless combustion system or air pollution control device capable of achieving 95% emissions reduction.

For all piping components, a monthly AVO inspection must be conducted. Leaking components must have a first attempt to repair within 5 calendar days, with repair completed as soon as practicable but no later than 15 calendar days unless delay of repair is necessary. Delay of repair is allowed if a shutdown is required for repair, which must be completed before the end of the first facility shutdown after the leak is detected.

NEW MEXICO

The New Mexico Environment Department (NMED) proposed a regulation on May 6, 2021, to establish emissions standards for VOC and NO_X for oil and gas production and processing sources located in areas where ozone concentrations are exceeding 95% of the NAAQS.

The proposed rule applies to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

The proposed rule contains NO_X and VOC reduction measures for engines and turbines, compressor seals, control devices, natural gas well liquids unloading, glycol dehydrators, heaters, hydrocarbon liquid transfers, pig launching and receiving, pneumatic controllers and pumps, storage tanks and workovers.

NMED proposed storage vessels requirements are 95% control efficiency for storage vessels with PTE between 2 TPY and 10 TPY and 98% control efficiency for storage vessels with PTE greater than or equal to 10 TPY.

NMED proposed requirements that pneumatic controllers be non-emitting at facilities with access to commercial electricity. For well sites without access to commercial electricity, the proposed requirement is that between 80% and 90% of pneumatic controller sites be non-emitting by 2030, based on the historic percentage of non-emitting controllers. For natural gas compressor stations and processing plants without access to commercial electricity the proposed requirement is that 98% of pneumatic controllers are non-emitting by 2030.

NMED proposed a requirement that pneumatic pumps be non-emitting at processing plants and at well sites and compressor stations with access to commercial electricity. For well sites and compressor stations without access to commercial electricity, the proposed requirements are that pneumatic pump emissions be routed to a control device if it is technically feasible and that VOC emissions be reduced by 95%.

NMED proposed requirements for reciprocating compressors and centrifugal compressors identical to the 2016 O&G CTG.

NMED proposed LDAR provisions require AVO on a 10 BOE per day production threshold; AVO requirements includes for sources at well sites, tank batteries, gathering and boosting stations, processing plants, and transmission compressor stations. New Mexico requires instrument-based LDAR on PTE basis, with well sites and tank batteries requiring annual at less than 2 TPY PTE, semiannual at equal to or greater than 2 TPY but less than 5 TPY PTE, and quarterly at equal to or greater than 5 TPY PTE and gathering and boosting sites, processing plants, and transmission compressor stations requiring quarterly at less than 25 TPY PTE and monthly at equal to or greater than 25 TPY.

The public hearing held by New Mexico Environmental Improvement Board to consider NMED's proposed regulations targeting emissions of ozone precursor pollutants from the oil and natural gas sector began September 20, 2021, and concluded October 1, 2021. See EIB 21-27 (R).

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION

On November 8, 2018, the New York State Department of Environmental Conservation (NYSDEC) announced that it was developing a stakeholder regulation outline[24] and seeking public comment on a potential rulemaking for new requirements in the oil and natural gas sector. The regulation was proposed on April 21, 2021, with a public comment period that closed on July 20, 2021. The proposed regulation covers sources at oil and gas production sites; oil, condensate, and produced water separation and storage; natural gas storage; natural gas gathering and boosting; natural gas transmission and compressor stations; and natural gas metering and regulating stations. Sources covered by the proposed regulation include storage vessels, natural gas actuated pneumatic devices and pumps, centrifugal compressors, reciprocating compressors, blowdown activities, and leak detection and repair.[25]

Storage vessels installed prior to January 1, 2023 with PTE greater than or equal to 6 TPY VOC must have a vapor control efficiency of 95%. Storage vessels installed on or after January 1, 2023 with PTE greater than or equal to 6 TPY VOC must not vent to the atmosphere.

Beginning January 1, 2023, continuous bleed natural gas pneumatic devices shall not vent natural gas to the atmosphere and comply with LDAR requirements. Continuous bleed natural gas-driven pneumatic controllers installed prior to January 1, 2023, may be used as long as it has a bleed rate less than or equal to 6 scfh and is clearly marked with a permanent tag identifying the natural gas flow rate as less than or equal to 6 scfh. All continuous bleed devices must be tested by a direct measurement method by January 1, 2024, and tested annually thereafter and any with a measured flow rate greater than 6 scfh must be repaired within 14 days. Continuous bleed natural gas actuated pneumatic devices and pumps that need to be replaced or retrofitted by collecting all vented natural gas using a vapor collection system or by using compressed air or electricity to operate.

Beginning January 1, 2023, intermittent bleed natural gas actuated pneumatic devices shall comply with LDAR requirements.

Beginning January 1, 2023, natural gas-actuated pneumatic pumps shall not vent natural gas to the atmosphere and comply with LDAR requirements.

Beginning January 1, 2023, components on driver engines and compressors at natural gas transmission compressor stations and natural gas underground storage facilities must comply with LDAR requirements. The compressor rod packing or seal emission flow rate shall be measured annually by direct measurement while the compressor is running at normal operating temperature; a rod packing or seal flow rate greater than 2 scfm or a combined flow rate greater than 2 scfm multiplied by the number of compression cylinders Reciprocating natural gas compressors that operate fewer than 200 hours over a 12 month period are exempt

[24] NYSDEC, Oil and Natural Gas Sector Emissions in New York Stakeholder Regulation Outline, November 2018, https://www.dec.ny.gov/docs/air_pdf/oilgasoutline.pdf
[25] See Proposed 6 NYCRR Part 203, https://www.dec.ny.gov/docs/air_pdf/prop203.pdf

as long as they are equipped with a non-resettable hour meter and records of the operating hours per month are maintained for five years and reported to the Department once per year.

Beginning January 1, 2023, centrifugal compressors at natural gas transmission compressor stations and natural gas underground storage facilities with wet seals shall control the wet seal vent gas using a vapor collection system or be replaced with a dry seal. Components on driver engines and compressors that use a wet seal or a dry seal shall comply with LDAR requirements. The wet seal emission flow rate shall be measured annually by direct measurement while running at normal operating temperature; a wet seal emission flow rate greater than 3 scfm or a combined flow rate greater than 3 scfm multiplied by the number of wet seals must be repaired within 30 days unless it is a critical component in which case the wet seals must be repaired no later than 12 months. Alternatively, the wet seal may be replaced with a dry seal no later than 18 months after the exceedance. Centrifugal natural gas compressors that operate fewer than 200 hours over a 12 month period are exempt as long as they are equipped with a non-resettable hour meter and records of the operating hours per month are maintained for five years and reported to the Department once per year.

For components subject to LDAR requirements at well sites shall be inspected semiannually using Method 21, OGI, or an approved alternative method. If using an approved alternative method using continuous monitoring, one Method 21, OGI, or approved alternative method inspection shall be conducted over 24 months. For components subject to LDAR requirements at gathering and boosting stations or the city gate shall be inspected quarterly using Method 21, OGI, or an approved alternative method. If using an approved alternative method using continuous monitoring, one Method 21, OGI, or approved alternative method inspection shall be conducted over 12 months. For components subject to LDAR requirements at natural gas transmission compressor stations or storage facilities shall be inspected bimonthly using Method 21, OGI, or an approved alternative method. If using an approved alternative method using continuous monitoring, one Method 21, OGI, or approved alternative method inspection shall be conducted over 12 months. The Method 21 leak definition is 500 ppm. The OGI leak definition is any visible emission. Leaking equipment must be repaired or replaced within 30 days of discovery unless it is a critical component. Repaired or replaced components must be resurveyed within 15 days. Critical components must be repaired by the end of the next process shutdown or within 12 months, whichever is sooner.

The rule also has recordkeeping and reporting requirements for pipeline or compressor station blowdowns greater than 10,000 scf and for pigging activities along natural gas pipelines.

It should be noted that New York has had a high-volume hydraulic fracturing ban in place since 2010.

OHIO ENVIRONMENTAL PROTECTION AGENCY

On November 20, 2018, the Ohio Environmental Protection Agency (Ohio EPA) issued a request for preliminary input from stakeholders on potential regulations aimed at air pollution emissions from unconventional oil and gas facilities not currently covered by existing permits and/or state regulations.[26] The regulations would have covered similar equipment and requirements currently covered in the 2016 NSPS, as well as Ohio EPA's oil and gas general permits. The regulations would have also covered both existing and new sources, such as oil and gas well sites and gas compressor stations.

However, Ohio EPA decided not to develop rules for existing sources as most of the wells in Ohio were developed after the promulgation of 40 CFR Part 60, Subpart OOOO. Ohio EPA's general permits currently

[26] Ohio EPA, Early Stakeholder Outreach- New Rules Regulating Emissions from the Oil and Gas Industry, Nov. 16, 2018, https://www.epa.ohio.gov/Portals/27/regs/3745-31/ESO_NewOilandGasRules_2018.pdf

contain the Subpart OOOO requirements and will be updated with new requirements after the EPA finalizes the changes to 40 CFR Part 60, Subpart OOOOa.

COMPARISON OF THIS FINAL-FORM RULEMAKING WITH REGULATIONS IN OTHER STATES

This final-form rulemaking is less stringent than CARB's methane requirements; however, it is more stringent than CARB's LDAR requirements as the quarterly instrument-based inspections required by this final-form rulemaking use a leak definition of 500 ppm as methane for all types of components, with no allowances for number or size of leaks as in the CARB program. The LDAR requirements of this final-form rulemaking are more stringent than both SCAQMD's and SJVAPCD's LDAR requirements as these two California programs have allowable numbers of leaks based on the detected concentration.

The storage vessel requirements in Colorado are slightly more stringent than this final-form rulemaking in that the VOC emission threshold is 2 TPY in ozone nonattainment areas, although the control efficiency required is lower than in this final-form rulemaking at well sites (90% from May to September and 70% from October to April). In the rest of the state, the Colorado requirement is for a 98% reduction for combustion control devices installed on or after May 1, 2014. This final-form rulemaking requires a 95% reduction to maintain consistency with the requirements in the Department's general permits and Federal regulations and allow owners or operators to use manufacturer-tested models. Generally, however, the manufacturer-tested models typically achieve significantly greater than 95% control in practice.

This final-form rulemaking is more stringent than Colorado's regulations for the owners or operators of reciprocating compressors at well sites. These owners or operators are required to perform rod packing changes or route rod packing emissions through a collection system to a control or process.

This final-form rulemaking is more stringent than Colorado's regulations regarding LDAR for well sites as Colorado has an inspection frequency ranging from annual to semiannual based upon the production facility's VOC emissions. The instrument-based LDAR inspection frequency requirement established in this final-form rulemaking is quarterly for well sites producing equal to or greater than 15 BOE per day with at least one well producing equal to or greater than 15 BOE per day and annually for well sites producing equal to or greater than 15 BOE per day with at least one well producing equal to or greater than 5 BOE per day. This final-form rulemaking is more stringent than Colorado's regulations regarding LDAR for compressor stations as Colorado has an inspection frequency ranging from annual to monthly based upon the compressor station's VOC emissions. Processing plants are required to meet the conditions of Subpart OOOO or OOOOa, as applicable. The instrument-based LDAR inspection frequency requirement established in this final-form rulemaking is quarterly for the owners or operators of gathering and boosting stations and natural gas processing facilities in this Commonwealth.

The requirements for the owners or operators of natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps and centrifugal compressor wet seal degassing systems in Colorado's regulations and this final-form rulemaking are identical.

This final-form rulemaking is more stringent than Maryland, as Maryland has filed a negative declaration with the EPA. However, the proposed requirements under Maryland's methane rule for LNG (liquified natural gas) facilities and compressor stations are more stringent than this final-form rulemaking for continuous bleed pneumatic controllers and reciprocating compressors. The proposed requirements for fugitive emissions components are slightly less stringent than this final-form rulemaking due to the 30-day repair requirement.

This final-form rulemaking is more stringent than Montana's regulations for storage vessels as the threshold in this final-form rulemaking is 2.7 TPY PTE, which is less than Montana's 15 TPY PTE VOC emission required control. This final-form rulemaking is also more stringent than Montana's regulations for fugitive emissions as Montana only requires monthly AVO inspections.

New Mexico's proposal is more stringent than this final-form rulemaking for storage vessels, as the initial VOC emission threshold is 2 TPY and the control efficiency required increases to 98% for those with VOC emissions above 10 TPY. New Mexico's proposal is also more stringent than this final-form rulemaking for pneumatic controllers and pneumatic pumps. New Mexico's proposal is more stringent than this final-form rulemaking as the LDAR requirement ranges from quarterly to monthly based on the facility's VOC PTE.

New Mexico's proposal is less stringent than this final-form rulemaking for reciprocating compressors at well sites. The requirements for centrifugal compressors are identical to this final-form rulemaking. New Mexico's proposal is also less stringent than this final-form rulemaking as the LDAR requirement ranges from annual to quarterly based on the facility's VOC PTE.

New York's proposal contains elements that are less stringent than this final-form rulemaking, as well as more stringent than this final-form rulemaking. Proposed requirements for storage vessels, reciprocating compressors, and fugitive emissions components at well sites, gathering and boosting stations, and processing plants are all less stringent. New York's proposal is more stringent than this final-form rulemaking for pneumatic controllers and pumps at well sites and gathering and boosting stations. The fugitive emissions component requirements for gathering and boosting stations are identical.

The requirements of this final-form rulemaking are more stringent than the proposal offered by Ohio considering their decision to not pursue an existing source rule. This final-form rulemaking is more stringent than Subparts OOOO and OOOOa as it establishes a 2.7 TPY threshold for storage vessels, requires the owners or operators of reciprocating compressors at well sites to perform rod packing changes or route rod packing emissions through a collection system to a control or process, and requires more frequent LDAR inspections.

With the exception of storage vessels, reciprocating compressors, and fugitive emissions components, the control measures established in this final-form rulemaking are consistent with and not more stringent than the recommendations of the 2016 O&G CTG. For storage vessels, reciprocating compressors, and fugitive emissions components, the requirements of this final-form rulemaking are cost-effective and necessary to attain and maintain the ozone NAAQS. This ensures that this Commonwealth will not be at a competitive disadvantage with other states.

(13) Will the regulation affect any other regulations of the promulgating agency or other state agencies? If yes, explain and provide specific citations.

No other Department regulations or regulations of other Commonwealth agencies are affected by this final-form rulemaking.

(14) Describe the communications with and solicitation of input from the public, any advisory council/group, small businesses and groups representing small businesses in the development and drafting of the regulation. List the specific persons and/or groups who were involved. ("Small business" is defined in Section 3 of the Regulatory Review Act, Act 76 of 2012.)

The Department consulted with the Air Quality Technical Advisory Committee (AQTAC) and the Small Business Compliance Advisory Committee (SBCAC) in the development of the proposed rulemaking. On December 14, 2017, the Department presented concepts to AQTAC on a potential rulemaking incorporating the 2016 O&G CTG recommendations. The Department returned to AQTAC on December 13, 2018, for an informational presentation on a preliminary draft Annex A. The proposed rulemaking was presented for a vote to AQTAC on April 11, 2019, and SBCAC on April 17, 2019. Both committees concurred with the Department's recommendation to move the proposed rulemaking forward to the Board for consideration.

The Department also conferred with the Citizens Advisory Council's (CAC) Policy and Regulatory Oversight Committee concerning the proposed rulemaking on May 7, 2019. On June 18, 2019, the full CAC concurred with the Department's recommendation to move the proposed rulemaking forward to the Board for consideration.

The Department also met with industry and environmental stakeholders to receive additional input on the proposed rulemaking. On January 24, 2019, the Department updated the Pennsylvania Grade Crude Development Advisory Council on the status of the proposed rulemaking. On March 21, 2019, the Department provided an informational presentation to the Oil and Gas Technical Advisory Board. On July 8, 2019, the Department met with industry stakeholders, including representatives from the Marcellus Shale Coalition, Penn Energy, Southwestern Energy, Range Resources, and Chesapeake Energy. On August 27, 2019, the Department met with environmental stakeholders, including representatives from PennFuture, Environmental Defense Fund, and the Clean Air Council.

The Board adopted the proposed rulemaking at its meeting of December 17, 2019 by an 18 to 1 vote. The proposed rulemaking was published at 50 Pa.B. 2633 (May 23, 2020). Due to requirements to mitigate the spread of the COVID-19 virus, the Board held three virtual public hearings on June 23, 24 and 25, 2020. A 66-day public comment period closed on July 27, 2020. The Board received 4,510 written comments and 121 individuals provided verbal testimony at the virtual public hearings. The written comments included individual letters and petitions with multiple signatories, so the total number of persons expressing interest in the proposed rulemaking was approximately 36,100. The Independent Regulatory Review Commission separately provided comments on the proposed rulemaking. The comments received on the proposed rulemaking are summarized in the Preamble to this final-form rulemaking and are also addressed in a separate Comment and Response Document that accompanies this final-form rulemaking. All comments on the proposed rulemaking were considered and addressed.

This final-form rulemaking was presented to AQTAC on December 9, 2021, the CAC Policy and Regulatory Oversight Committee on January 12, 2022 and the CAC on January 18, 2022, and SBCAC on January 27, 2022.

(15) Identify the types and number of persons, businesses, small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012) and organizations which will be affected by the regulation. How are they affected?

The 2016 O&G CTG listed the following five North American Industry Classification System (NAICS) codes to identify businesses potentially covered by the 2016 O&G CTG. The NAICS is an industry classification system developed by Canada, Mexico and the United States that groups establishments into industry groups based on the economic activities, producing and nonproducing, in which the establishment is primarily engaged. More information about the United States portion of the NAICS is available at: http://www.census.gov/eos/www/naics/.

The types of persons, businesses, small businesses, and organizations in this Commonwealth that would be affected by this final-form rulemaking are the same as those identified in the 2016 O&G CTG:

1. 211111 Crude Petroleum and Natural Gas Extraction.
2. 211112 Natural Gas Liquid Extraction.
3. 221210 Natural Gas Distribution.
4. 486110 Pipeline Distribution of Crude Oil.
5. 486210 Pipeline Transportation of Natural Gas.

In 2017, these five NAICS codes were changed to the following codes with potentially affected sources, which should not affect the scope of sources affected in this Commonwealth:

1. 211120 Crude Petroleum Extraction.
2. 211130 Natural Gas Extraction.
3. 221210 Natural Gas Distribution.
4. 486110 Pipeline Distribution of Crude Oil.
5. 486210 Pipeline Transportation of Natural Gas.

In addition, there are two additional NAICS codes used by the oil and natural gas industry to report emissions to the Department's Air Information Management System (AIMS) database:

1. 213111 Drilling Oil and Gas Wells.
2. 486990 All Other Pipeline Transportation.

The United States Small Business Administration (SBA) has established definitions of what constitutes a small business concern and publishes a list of size standards for each NAICS code. See 13 CFR 121.201. The size standard, usually stated in number of employees or average annual receipts, represents the largest size that a business (including its subsidiaries and affiliates) may be to remain classified as a small business for SBA and Federal government programs. For crude petroleum extraction (211120) and natural gas extraction (211130), the SBA size definition is 1,250 employees. For natural gas distribution (221210) and drilling oil and gas wells (213111), the SBA size definition is 1,000 employees. For pipeline distribution of crude oil (486110), the SBA size definition is 1,500 employees. For pipeline transportation of natural gas (486210), the SBA size definition is $30 million in annual receipts. For all other pipeline transportation (486990), the SBA size definition is $40.5 million in annual receipts.

The Department gathered information about potentially affected facility owners or operators from the Environmental Facility Application Compliance Tracking System (eFACTS) database and the AIMS database. The eFACTS database contains facility-specific information, including NAICS code, for permitted facilities and some previously inspected facilities for which permits are not required. The AIMS database contains site-specific source and air pollutant emissions data, as well as NAICS codes, to maintain the air quality emission inventory. The eFACTS and AIMS databases include only those owners or operators of facilities with which the Department has had contact and for which the Department has a reason to input data. These owners or operators may or may not meet the definition of "small business" in accordance with Section 3 of the Regulatory Review Act (71 P.S. § 745.3).

The Department identified 5,039 client ID numbers for owners or operators of facilities in this Commonwealth using the Department's eFACTS and AIMS databases and the NAICS codes covered by the 2016 O&G CTG. These facilities include approximately 30,648 well sites, 486 gathering and boosting stations, and 15 natural gas processing facilities in this Commonwealth. A single client ID entity may own or operate more than one type of facility and may own or operate multiple facilities of the same facility type. The owners or operators of these facilities are all potentially subject to this final-form rulemaking as they are likely to have air contamination sources subject to this final-form rulemaking.

The Department categorized the 5,039 owners or operators based on their client type in eFACTS. Of the 5,039 owners or operators, the Department determined that 3,783 owners or operators have a "for profit" client type of estate/trust, individual, non-government, partnership-general, partnership-limited, or sole proprietorship. The Department assumed that these 3,783 "for profit" entities are likely a small business. The Department determined that 1,170 of the 5,039 owners or operators have a "for profit" client type of limited liability company, limited liability partnership, non-Pennsylvania corporation, or Pennsylvania corporation. The Department assumed that each of these 1,170 "for profit" entities is not a small business unless it meets the applicable SBA size definition based on the data available. The remaining 86 owners or operators with the client type of association/organization, authority, county, Federal agency, municipality, other (government), school district, or state agency are classified as "not for profit" client types. These types are not considered small businesses.

The Department requested the assistance of the Commonwealth's Small Business Development Center's (SBDC) Environmental Management Assistance Program (EMAP) in reviewing the list of "for profit" 1,170 owners or operators for their small business-size status. The SBDC EMAP searched the Hoover's database and found 117 entries for the 1,170 owners or operators and provided the Hoover's data for these 117 facilities to the Department. The Department reviewed the Hoover's data for these 117 facility owners or operators and determined that 51 facilities meet the definition for small business size for the applicable NAICS code. Based on the above assumptions and analyses, the Department estimates that as many as 3,834 of the 5,039 owners or operators identified may meet the definition of small business as defined in Section 3 of the Regulatory Review Act.

The Department estimates an annual compliance cost of $31.7 million per year for the 5,039 owners or operators and an annual $20.3 million per year in savings due to conserving the natural gas rather than losing it through uncontrolled VOC emissions. See the discussion in the response to Question 17 for how these financial estimates are derived.

The Department estimates that the potentially affected 5,039 Pennsylvania facility owners or operators, including small business-sized owners or operators, could incur an average annual cost of approximately $6,285 per owner or operator. The Department estimates that each owner or operator could accrue an average annual savings from conservation of natural gas, assuming a price of $1.70 per thousand cubic feet (Mcf) of natural gas, of approximately $4,023 per owner or operator. This amounts to a net cost per owner or operator of approximately $2,263.

As an alternative to the average costs per owner or operator cited above, an average cost can be generated using the average cost per facility and multiplying by the number of facilities the owner or operator controls. The Department estimates that, for the 31,149 potentially affected facilities, the average annual cost per facility is approximately $1,017 and the average annual savings from conservation of natural gas is approximately $651. This results in an average net cost per facility of approximately $366.

The VOC emissions reductions from the potentially affected 31,149 facilities are estimated to be 12,068 TPY. See the discussion in the response to Question 17 for the details on estimated VOC emissions reductions. The estimated average amount of potential VOC emission reductions per affected facility is approximately 0.4 TPY. The estimated average VOC emission reductions per affected facility owner or operator will vary depending on the types of affected sources being monitored and controlled at the facility. The average cost per ton of reducing VOC emissions is approximately $2,625 and the average net cost per ton of reducing VOC emissions is approximately $945.

Except for the requirements for storage vessels, reciprocating compressors at well sites, and fugitive emissions components, some of the potentially affected facility owners or operators, including small businesses, are likely in compliance with this final-form rulemaking for certain covered sources under 40 CFR Part 60, Subparts OOOO and OOOOa. Certain owners or operators may likely be in compliance with the requirements of this final-form rulemaking through compliance with existing operating permits, general permits, or exemption requirements. It is important that an owner or operator compare the requirements of this final-form rulemaking and their current requirements and insure they comply with the more stringent VOC emission control requirements.

(16) List the persons, groups or entities, including small businesses, that will be required to comply with the regulation. Approximate the number that will be required to comply.

This final-form rulemaking will apply statewide to owners or operators of one or more of the following oil and natural gas sources of VOC emissions which were constructed on or before the effective date of this final-form rulemaking: storage vessels in all segments except natural gas distribution, natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, centrifugal compressors and reciprocating compressors and fugitive emission components.

As discussed in detail in Question 15, the Department identified 5,039 client ID numbers for owners or operators of the approximately 31,149 facilities in this Commonwealth. Based on the analysis described in the response to Question 15, approximately 3,834 of the 5,039 owners or operators may meet the definition of small business as defined in Section 3 of the Regulatory Review Act. Based on information supplied by commentators, the Oil and Gas Production Report, and AIMS, the Department estimates there are 30,648 well sites, 486 gathering and boosting stations, 15 processing plants, and 121 transmission stations. The Department estimates that these owners or operators have at least 51 storage vessels at 18 facilities, 34,856 pneumatic controllers at 31,134 facilities, and 40 pneumatic pumps at 17 facilities will be subject to requirements under this final-form rulemaking. The owners or operators of approximately 2,711 of 30,648 well sites will be required to implement instrument-based LDAR inspections or increase the current instrument-based LDAR inspection frequency under this final-form rulemaking. The owners or operators of approximately 263 of 486 gathering and boosting stations and 1 of 15 processing plants will be required to implement a new instrument-based LDAR inspection program or will be subject to new requirements under this final-form rulemaking.

(17) Identify the financial, economic and social impact of the regulation on individuals, small businesses, businesses and labor communities and other public and private organizations. Evaluate the benefits expected as a result of the regulation.

The Department estimates that the total industry-wide cost of complying with this final-form rulemaking will be about $31.7 million per year. However, implementation of the control measures will also potentially save owners or operators in the oil and natural gas industry about $20.3 million per year due to a lower natural gas loss rate during production. This cost estimate consists of two major categories of data. The first is the annual cost to implement the RACT requirements for each affected source or affected facility as provided by the EPA in the 2016 O&G CTG and from the Department's own additional analysis. The second is the number of potentially affected facilities, which was obtained from several data sources including the Department's Oil and Gas Production Report, eFACTS, and AIMS. For the owners or operators of facilities in the oil and natural gas industry, the anticipated annual cost to comply with the requirements will be based on the type of sources present at the site, the requirements that apply to those sources, and the type of control used to comply.

Most of the anticipated costs are due to new regulatory requirements but many of the costs associated with this final-form rulemaking are from common sense practices and controls, some of which owners or operators may already be implementing due to regulatory requirements or voluntary emission reduction programs. An example includes periodic AVO inspections which can prevent natural gas releases, which in turn prevents environmental damage and significant financial losses for the operator. The Department anticipates there will be areas of cost savings that will occur as a result of this final-form rulemaking. The Department estimates a majority of small business stationary sources will be below the applicability thresholds. However, affected small businesses may incur minimal cost as a result of this final-form rulemaking; net costs of approximately $366 per facility or, on average, $2,263 per owner or operator as discussed in Question 15. Overall, the Department does not anticipate that this final-form rulemaking will result in any significant adverse impact on small oil and gas operators.

The Department estimates that implementation of the proposed control measures could reduce VOC emissions by as much as 12,068 TPY. Approximately 714 TPY of these VOC emission reductions are due to the RACT determinations by the Department that reduce emissions over and above the EPA's RACT recommendations. These reductions would benefit the health and welfare of the approximately 12.8 million residents and the numerous animals, crops, vegetation and natural areas of this Commonwealth by reducing the amount of ground-level ozone air pollution resulting from these sources.

While this final-form rulemaking requires VOC emission reductions, methane emissions are also reduced as a co-benefit, because both VOC and methane are emitted from oil and gas operations. Except for storage vessels, the requirements for control of emissions are not dependent on an applicability threshold for VOC, meaning that most requirements have no minimum level of VOC emissions under which sources are granted an exemption. The control measures implemented for VOC emissions simultaneously control methane emissions and could reduce methane emissions by as much as 221,066 TPY with 41 TPY from the installation of controls for storage vessels, 175,171 TPY from pneumatic controllers, 135 TPY from pneumatic pumps, 1,172 TPY from replacement of reciprocating compressor rod packings at well sites, and 44,547 TPY from fugitive emissions components through the performance of LDAR inspections. Approximately 11,913 TPY of the methane emission reductions are due to the technically and economically feasible VOC RACT determination by the Department that is over and above the reductions from EPA's VOC RACT recommendations.

As discussed in the responses to Questions 8 and 10, adoption of the VOC emission control measures and other requirements in this final-form rulemaking would allow the Commonwealth to make substantial progress in achieving and maintaining the 1997, 2008, and 2015 8-hour ozone NAAQS statewide. Implementation of and compliance with the proposed VOC emission reduction measures would also assist the Commonwealth in reducing the levels of ozone precursor emissions that contribute to potential nonattainment of the 2015 ozone NAAQS. As a result, the VOC emission control measures are reasonably necessary to attain and maintain the health-based and welfare-based 8-hour ozone NAAQS in this Commonwealth and to satisfy related CAA requirements.

In addition, as discussed in the response to Question 10, the reductions of ozone are estimated to have a health benefit to the residents of the Commonwealth ranging from $63 million to $189 million. The Department is not stating that these estimated monetized health benefits would all be the result of implementing the RACT measures, but the EPA estimates are indicative of the benefits to Commonwealth residents of attaining the 2015 8-hour ozone NAAQS through the implementation of a suite of measures to control VOC emissions in the aggregate from different source categories. Reducing VOC and attaining the 2015 ozone NAAQS will serve to protect over 600,000 jobs and $163 billion in revenue in the agriculture and forestry industry according to information provided to the Department by the Pennsylvania Department of Agriculture (PDA).[6]

(18) Explain how the benefits of the regulation outweigh any cost and adverse effects.

As discussed in the response to Question 9, VOC emissions are precursors to the formation of ground-level ozone, a public health, welfare and environmental hazard. Benefits of implementing the requirements of this final-form rulemaking include natural gas savings of $20.3 million for the oil and natural gas industry. Additional benefits include making progress toward achieving between $63 million to $189 million in health benefits to the residents of this Commonwealth as a result of attaining the 2015 8-hour ozone NAAQS, and protecting over 600,000 jobs and $163 billion in revenue in the agriculture and forestry industries.[4,6] Costs of implementing the requirements of this final-form rulemaking include $31.7 million to the oil and natural gas industry. Industry therefore will incur a net cost of $11.4 million, while the Commonwealth as a whole will incur a net benefit of at least $51.6 million when using a baseline minimum of $63 million in public health benefits, plus additional benefit from the preservation of jobs and revenue from the agriculture and forestry industries.

Ozone precursor emission reductions achieved through the implementation of RACT requirements and RACT emission limitations for the affected sources would help the Commonwealth attain and maintain the 1997, 2008 and 2015 ozone NAAQS. Given that implementation of RACT requirements is federally required, the Department estimates that the RACT requirements and RACT emission limitations would achieve greater VOC emission reductions at a reasonable cost to the affected owners and operators and to the Commonwealth than not implementing this final-form rulemaking.

While this final-form rulemaking requires VOC emission reductions, methane emissions are also reduced as a co-benefit, because both VOC and methane are emitted from oil and gas operations. As detailed in the response to Question 17, the control measures implemented for VOC emissions simultaneously control methane emissions and provide VOC emission reductions of approximately 12,068 TPY and methane emission reductions of approximately 221,066 TPY. The technically and economically feasible RACT determinations in this final-form rulemaking for storage vessels, reciprocating compressors at well sites, and fugitive emissions components result in a greater reduction of VOC emissions than implementing the EPA's RACT recommendations from the 2016 O&G CTG resulting in an additional 714 TPY of VOC and 11,913 TPY of methane emissions reductions. As discussed in the response to Question 10, the co-benefit methane reductions will help achieve Governor Tom Wolf's Methane Reduction Strategy, resulting in associated health and environmental benefits.

The improvements in ground-level ozone air quality and groundwater quality through reduced emissions of VOCs would provide economic and social benefits through reduced need for medical treatment for asthma and other lung-related illnesses and reduced costs for repairing damage to infrastructure, as well as through improved crop yields, healthier forests and wildlife, and increased tourism to see the beautiful natural areas of this Commonwealth.

This final-form rulemaking may create economic opportunities for VOC emission control technology innovators, manufacturers, and distributors through an increased demand for new or improved equipment. In addition, the owners or operators of regulated facilities may be required to install and operate an emissions monitoring system or equipment necessary for an emissions monitoring method to comply with this final-form rulemaking, thereby creating an economic opportunity for the emissions monitoring industry.

(19) Provide a specific estimate of the costs and/or savings to the regulated community associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.

Compliance costs will vary for each facility depending on which compliance option is chosen by the owner or operator.

Storage vessels

The annualized cost of $25,194 in 2012 dollars to control one storage vessel with a control device is based on the data in the 2016 O&G CTG, which is equivalent to $30,909 in 2021 dollars. The Department's additional analysis demonstrated that the annualized cost of routing emissions from a storage vessel to a control device ranges from $9,501 to $22,871 in 2021 dollars based on the data in the Department's Technical Support Document (TSD) for the General Plan Approval/General Operating Permit BAQ-GPA/BP-5 (GP-5) for natural gas compression stations, processing plants, and transmission stations and the General Plan Approval/General Operating Permit BAQ-GPA/GP-5A (GP-5A) for unconventional natural gas well site operations and remote pigging stations.[27] The Department used the EPA's annualized cost estimate of $30,909 in 2021 dollars to be conservative when estimating the effect on the oil and natural gas industry. The Department identified a total of 31,270 facilities with storage vessels from the Department's databases. There are 18 facilities with 51 storage vessels that emit 2.7 TPY or more of VOC with a total industry cost of $556,359 per year. The Department estimates that implementation of the final-form rulemaking control measures could reduce VOC emissions by as much as 282 TPY from the installation of controls for storage vessels. This results in an average cost of approximately $1,973 per ton of VOC emissions reduced per year. Approximately 18 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

Natural gas-driven continuous bleed pneumatic controllers

The annualized cost of $296 in 2012 dollars to replace a continuous high-bleed pneumatic controller with a low-bleed pneumatic controller is based on the data in the 2016 O&G CTG, which is $347 per year in 2021 dollars. The Department identified a total of 31,134 facilities with an estimated 34,856 affected pneumatic controllers. The total industry cost is $12,085,272 per year. Using the EPA's estimate of natural gas emissions per controller and this Commonwealth's average natural gas composition, the Department estimates that implementation of the final-form rulemaking control measures could reduce VOC emissions by

[27] DEP, Technical Support Document For the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), June 2018, http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=19616&DocName=02%20FINAL%20TECHNICAL%20SUPPORT%20DOCUMENT%20FOR%20GP-5%20(2700-PM-BAQ0267)%20AND%20GP-5A%20(2700-PM-BAQ0268).PDF%20%20%3Cspan%20style%3D%22color%3Agreen%3B%22%3E%3C%2Fspan%3E%20%3Cspan%20style%3D%22color%3Ablue%3B%22%3E%3C%2Fspan%3E

as much as 9,102 TPY from pneumatic controllers located at these facilities. The requirements for natural gas-driven continuous bleed pneumatic controllers are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost effective.

Natural gas-driven diaphragm pumps

The annualized cost of $774 in 2012 dollars to control one natural gas-driven diaphragm pump is based on the data in the 2016 O&G CTG, which is $907 per year in 2021 dollars. The Department identified 17 well sites with an estimated 40 affected diaphragm pumps. The total industry cost is $36,265 per year. Using the EPA's estimate of natural gas emissions per pump, this Commonwealth's average natural gas composition, and a 95% emissions reduction, the Department estimates that implementation of the final-form rulemaking control measures could reduce VOC emissions by as much as 7 TPY from natural gas-driven diaphragm pumps. The requirements for natural gas-driven diaphragm pumps are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

Reciprocating compressors

The annualized cost of $782 in 2021 dollars to replace the rod packings for one reciprocating compressor at a well site is based on the data in the Department's TSD for GP-5 and GP-5A. The Department identified 448 well sites reporting a total of 535 engines. The Department assumes that all of the engines drive reciprocating compressors. The total industry cost is $418,456 per year. The Department estimates that implementation of the final-form control measures could reduce VOC emissions by as much as 61 TPY due to the replacement of reciprocating compressor rod packings located at well sites. The Department has determined this requirement to be cost-effective since the annualized cost is only $782 per year, which is the sum of the annualized capital cost and the annual operating expenses. Annualized cost is one of many factors that the Department can consider when determining the cost-effectiveness of a control device or control technique. The 61 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

There are an estimated 423 gathering and boosting stations with at least 527 reciprocating compressors and an estimated 11 natural gas processing plants with at least 30 reciprocating compressors. The Department assumes that the owners or operators of these facilities are complying with the requirements of Subparts OOOO and OOOOa as none of these facilities were constructed prior to 2011. Therefore, they would have to do nothing further under this final-form rulemaking.

Centrifugal compressors

The annualized cost of $2,553 in 2012 dollars to control one wet seal degassing system for a centrifugal compressor is based on the data in the 2016 O&G CTG which is $2,990 in 2021 dollars. The Department identified 3 gathering and boosting stations reporting at least 7 turbines and 2 processing plants reporting at least 2 turbines. The Department assumes that all of the turbines drive centrifugal compressors. These centrifugal compressors are all likely to be dry seal centrifugal compressors and the owners or operators of these sources would not have applicable VOC emission control requirements under this final-form rulemaking. If one or more of these compressors is a wet seal centrifugal compressor, the owner or operator would be subject to the applicable wet seal degassing system VOC emission control requirements of this final-form rulemaking. VOC emissions would be reduced by 95% at a cost of $2,990 per year per wet seal degassing system in 2021 dollars. The requirements for wet seal centrifugal compressor degassing systems are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost effective.

Fugitive Emissions Components

In the 2016 O&G CTG, the annualized cost in 2012 dollars to conduct annual LDAR inspections at a well site is $1,318, to conduct quarterly LDAR inspections at a well site is $4,220, and to conduct quarterly LDAR inspections at a gathering and boosting station is $25,049. These costs are $1,554, $4,937, and $29,307 in 2021 dollars, respectively. The Department's TSD for GP-5 and GP-5A also contained cost data for implementing LDAR programs, which are more conservative than the annual costs in EPA's 2016 O&G CTG as the costs in the TSD are based on a contractor's quote. The annual cost for implementing an annual LDAR inspection program is $1,681 in 2021 dollars at a well site. The annual cost, in 2021 dollars, for implementing a quarterly LDAR inspection program is $6,723 at a well site and $13,447 for a gathering and boosting station or natural gas processing plant. It should be noted that the estimates for well sites assumed there are 1,000 components to monitor and that for gathering and boosting stations or natural gas processing plants there are 2,000 components to monitor. EPA's assumptions for the number of components to monitor are between 127 and 671 for well sites and 3,091 for gathering and boosting stations or processing plants.

The Department identified a total of 31,149 facilities including well sites, gathering and boosting stations, and natural gas processing plants. The calculation of fugitive emissions before control were based on estimates of the amount of natural gas leaked. The breakdown between the amounts of VOC and methane emissions is calculated using this Commonwealth's natural gas composition ratio of 4.47% VOC and 86.03% methane. The value of natural gas saved is calculated using the assumed cost of $1.70/Mcf of natural gas in 2021 dollars.

There are approximately 37 well sites with no LDAR program currently in place that the Department assumes will be required to implement an annual LDAR program. The total annualized cost is $62,192, reducing VOC emissions by approximately 136 TPY for a total cost per ton of VOC reduced of $1,457. The 136 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

There are approximately 1,525 well sites with no LDAR program currently in place that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $10,253,276, reducing VOC emissions by approximately 1,163 TPY. The Department has determined this requirement to be cost-effective since the annualized cost is only $6,723 per year. Approximately 291 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

There are approximately 499 well sites currently required to perform annual LDAR that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $2,516,255, reducing VOC emissions by approximately 314 TPY. The Department has determined this requirement to be cost-effective since the incremental annualized cost is only $5,042 per year. Approximately 79 TPY of the VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

There are approximately 650 well sites currently required to perform semiannual LDAR that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $2,185,125, reducing VOC emissions by approximately 517 TPY. The Department has determined this requirement to be cost-effective since the incremental annualized cost is only $3,361 per year. Approximately 129 TPY of the

VOC emissions reduction from this requirement is due to the technically and economically feasible RACT determination by the Department that is over and above the reductions from EPA's RACT recommendations.

There are approximately 263 gathering and boosting stations with no LDAR program currently in place based on their construction date, the lack of LDAR requirements in their permits, or that have no reported fugitive emissions components. The Department assumes these facilities will be required to implement a quarterly LDAR program. The total annualized cost is $3,536,561. Using the EPA's estimate of fugitive natural gas emissions per gathering and boosting station and this Commonwealth's average natural gas composition, the Department estimates a VOC emissions reduction of 473 tpy. The requirements for quarterly LDAR at natural gas gathering and boosting stations are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

There is one gathering and boosting station with an annual LDAR program currently in place that the Department assumes will be required to implement a quarterly program. The total annualized cost is $10,085. The requirements for quarterly LDAR at natural gas gathering and boosting stations are identical to the EPA's 2016 O&G CTG recommendation which the EPA has determined to be cost-effective.

There is one natural gas processing plant with no LDAR program currently in place that the Department assumes will be required to implement a quarterly LDAR program. The total annualized cost is $13,447 reducing VOC emissions by approximately 12 TPY for a total cost per ton of VOC reduced of $1,121.

The total industry cost is approximately $18,576,941 in 2021 dollars. The Department estimates that the final-form control measures could reduce VOC emissions by 2,616 TPY or more from the subject fugitive emissions components due to implementation of the required LDAR inspection program at these facilities.

Based on the above compliance costs, and the number of applicable sources, the Department estimates that this final-form rulemaking will cost affected owners or operators approximately $31.7 million (based on 2021 dollars) per year without consideration of the economic benefit of the saved natural gas. The value of the saved natural gas, assuming a natural gas price of $1.70 per Mcf in 2021 dollars, yields a savings of approximately $20.3 million, resulting in a total net cost of approximately $11.4 million for this final-form rulemaking.

This estimate consists of two major categories of data. The first is the cost per year to control each piece of equipment or site affected, which came from either the 2016 O&G CTG or the Department's TSD for GP-5 and GP-5A, as detailed in the response to Question 17. The second is the number of potentially affected facilities, which were obtained from several data sources including the Department's Oil and Gas Production Report, eFACTS, and AIMS. The cost per year to control each piece of equipment or site affected was multiplied by the number of each located in this Commonwealth. The costs for each category of sources were added together to come up with a final estimated cost and savings.

The VOC RACT requirements established by this final-form rulemaking will not require the owner or operator to obtain an operating permit or submit an application for amendments to an existing operating permit. These requirements will be incorporated into the existing operating permit when the permit is renewed, if less than 3 years remain in the permit term, as specified under 25 Pa. Code § 127.463(c) (relating to operating permit revisions to incorporate applicable standards). If 3 years or more remain in the permit term, the requirements would be incorporated as applicable requirements in the permit within 18 months of the promulgation of this final-form rulemaking, as required under § 127.463(b).

(20) Provide a specific estimate of the costs and/or savings to the local governments associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.

It is not anticipated that local governments will incur additional costs as a result of this final-form rulemaking.

(21) Provide a specific estimate of the costs and/or savings to the state government associated with the implementation of the regulation, including any legal, accounting, or consulting procedures which may be required. Explain how the dollar estimates were derived.

State government costs would include permit engineer review time for applications of plan approvals or operating permits as a result of any modifications or additions of infrastructure at oil and natural gas facilities required to comply with this final-form rulemaking. The Department would collect fees associated with applications submitted to cover these costs. See 25 Pa. Code Chapter 127 for more information on fees.

(22) For each of the groups and entities identified in items (19)-(21) above, submit a statement of legal, accounting or consulting procedures and additional reporting, recordkeeping or other paperwork, including copies of forms or reports, which will be required for implementation of the regulation and an explanation of measures which have been taken to minimize these requirements.

No new legal, accounting or consulting procedures are required to implement this final-form rulemaking.

(22a) Are forms required for implementation of the regulation?

No new forms would be required for the implementation of this final-form rulemaking. Forms needed to implement this final-form rulemaking exist and are currently part of the Air Quality program.

(22b) If forms are required for implementation of the regulation, attach copies of the forms here. If your agency uses electronic forms, provide links to each form or a detailed description of the information required to be reported. Failure to attach forms, provide links, or provide a detailed description of the information to be reported will constitute a faulty delivery of the regulation.

Not applicable, because no new forms are required for the implementation of this final-form rulemaking.

(23) In the table below, provide an estimate of the fiscal savings and costs associated with implementation and compliance for the regulated community, local government, and state government for the current year and five subsequent years.

As discussed in the response to Question 19, the Department estimates that this final-form rulemaking will cost affected owners or operators approximately $31.7 million in 2021 dollars per year without consideration of the economic benefit of the saved natural gas due to the reduced losses of uncontrolled emissions. The value of the saved natural gas, assuming a natural gas price of $1.70 per Mcf in 2021 dollars, yields a savings of approximately $20.3 million, resulting in a total net cost of approximately $11.4 million for this final-form rulemaking.

This estimate consists of two major categories of data. The first is the cost per year to control each piece of equipment or site affected, which came from either the 2016 O&G CTG or the Department’s TSD for GP-5 and GP-5A, as detailed in the response to Question 19. The second is the number of potentially affected facilities, which were obtained from several data sources including the Department's Oil and Gas Production Report, eFACTS, and AIMS. The cost per year for each affected source was multiplied by the number of each piece of equipment or affected site in the State. The costs for each category of sources were added together to come up with a final estimated cost and savings for the current fiscal year as shown in the Table below.

	Current FY (21/22)	**FY+1 (22/23)**	**FY+2 (23/24)**	**FY+3 (24/25)**	**FY+4 (25/26)**	**FY+5 (26/27)**
SAVINGS:	**$**	**$**	**$**	**$**	**$**	**$**
Regulated Community	20,270,177	20,675,581	21,089,092	21,510,874	21,941,092	22,379,914
Local Government	0.00	0.00	0.00	0.00	0.00	0.00
State Government	0.00	0.00	0.00	0.00	0.00	0.00
Total Savings	20,270,177	20,675,581	21,089,092	21,510,874	21,941,092	22,379,914
COSTS:						
Regulated Community	31,673,294	32,306,760	32,952,895	33,611,953	34,284,192	34,969,876
Local Government	0.00	0.00	0.00	0.00	0.00	0.00
State Government	0.00	0.00	0.00	0.00	0.00	0.00
Total Costs	31,673,294	32,306,760	32,952,895	33,611,953	34,284,192	34,969,876
REVENUE LOSSES:						
Regulated Community	0	0	0	0	0	0
Local Government	0.00	0.00	0.00	0.00	0.00	0.00
State Government	0.00	0.00	0.00	0.00	0.00	0.00
Total Revenue Losses	0	0	0	0	0	0

(23a) Provide the past three-year expenditure history for programs affected by the regulation.

Program	**FY-3 (18/19)**	**FY-2 (19/20)**	**FY-1 (20/21)**	**Current FY (21/22)**
Environmental Program Management (161-10382)	$30,932,000	$27,920,000	$32,041,000	$34,160,000
Clean Air Fund - Major Emission Facilities (215-20077)	$17,878,000	$18,759,000	$20,801,000	$20,083,000
Clean Air Fund - Mobile and Area Facilities (233-20084)	$9,369,000	$9,900,000	$11,290,000	$10,153,000

(24) For any regulation that may have an adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), provide an economic impact statement that includes the following:

(a) An identification and estimate of the number of small businesses subject to the regulation.

The Department expects a maximum of about 5,039 owners or operators of affected oil and natural gas sources may be subject to this final-form rulemaking. Of these potential 5,039 owners or operators, approximately 3,834 may meet the definition of small business as defined in Section 3 of the Regulatory Review Act. It is possible that far fewer than the 5,039 owners or operators will be subject to the control measures of this final-form rulemaking, depending on the amount of VOC emissions that are emitted by the affected sources they own or operate or if they are subject to other regulations in Chapter 129 or if the same or more stringent permit conditions are already incorporated in their operating permit. Please see the response to Question 15 for details about how the Department determined the number of potentially affected small businesses.

(b) The projected reporting, recordkeeping and other administrative costs required for compliance with the proposed regulation, including the type of professional skills necessary for preparation of the report or record.

The recordkeeping and reporting requirements for owners or operators of applicable sources under this final-form rulemaking are minimal because the records required are in line with the records already required to be kept for emission inventory purposes and for other Federal and State requirements.

Some of the affected facility owners or operators are subject to requirements under 40 CFR Part 60, Subpart OOOO, which has an effective date of August 23, 2011, or 40 CFR Part 60, Subpart OOOOa which has an effective date of September 18, 2015. The owners or operators of sources installed prior to August 23, 2011 would be required to determine applicability of this final-form rulemaking to all affected sources, keep additional records, and submit an annual report to demonstrate compliance with this final-form rulemaking. The owners or operators of sources installed after August 23, 2011 and prior to September 18, 2015 would be required to determine whether their storage vessels are affected sources based on the lowered applicability threshold in this final-form rulemaking, their natural gas-driven diaphragm pumps at their well sites or processing plants are affected sources, their reciprocating compressors at well sites are affected sources, and whether their fugitive emissions components at well sites are affected sources under this final-form rulemaking. This category would also be required under § 129.130 to keep additional records and submit additional information in their reports to show compliance with this final-form rulemaking. The owners or operators of sources installed after September 18, 2015, would be required to determine whether their storage vessels are affected sources based on the lowered applicability threshold in this final-form rulemaking, their reciprocating compressors at well sources are affected sources, and whether their fugitive emissions components at well sites are affected sources under this final-form rulemaking. This category would also be required under § 129.130 to keep additional records and submit additional information in their reports to show compliance with this final-form rulemaking. No special skills are required, and the Department only anticipates minimal administrative costs for those already complying with Subpart OOOO or Subpart OOOOa.

(c) A statement of probable effect on impacted small businesses.

The requirements of this final-form rulemaking apply to the owners or operators of the following types of oil and natural gas sources: storage vessels in all segments except natural gas distribution; natural gas-driven continuous bleed pneumatic controllers; natural gas-driven diaphragm pumps; reciprocating compressors and centrifugal compressors; and fugitive emissions components.

The Department identified 5,039 client ID numbers for potentially affected owners or operators of facilities in Pennsylvania using the Department's eFACTS and AIMS databases and the NAICS codes covered by the 2016 O&G CTG. These facilities include approximately 30,648 well sites, 486 gathering and boosting stations, and 15 natural gas processing facilities in this Commonwealth. The Department estimates that approximately 3,843 of the 5,039 owners or operators identified in eFACTS may meet the definition of small business as defined in Section 3 of the Regulatory Review Act. Please see the response to Question 15 for details about how the Department determined the number of potentially affected small businesses.

As discussed in detail in the response to Question 16, the Department estimates that these owners or operators have at least 51 storage vessels at 18 facilities, 34,856 pneumatic controllers at 31,134 facilities, and 40 pneumatic pumps at 17 facilities will be subject to requirements under this final-form rulemaking. The owners or operators of approximately 2,711 of 30,648 well sites will be required to implement instrument-based LDAR inspections or increase the current instrument-based LDAR inspection frequency under this final-form rulemaking. The owners or operators of approximately 263 of 486 gathering and boosting stations and 1 of 15 processing plants will be required to implement a new instrument-based LDAR inspection program or will be subject to new requirements under this final-form rulemaking.

As described in the response to Question 24(b), small businesses will have to determine applicability of their affected sources to this final-form rulemaking, keep new or additional records, and submit new reports or reports with additional information. No special skills are required, and the Department only anticipates minimal administrative costs for those already complying with Subpart OOOO or Subpart OOOOa.

While many of the anticipated costs are due to new regulatory requirements, many of the costs associated with this final-form rulemaking are from what the Department believes are best management practices and controls that affected owners or operators may already be implementing. Some examples include periodic inspections, which can prevent releases of natural gas emissions, which in turn prevent environmental damage and significant financial losses for the affected owner or operator. The Department also anticipates there may be areas of cost savings that may occur as a result of the implementation of the control measures in this final-form rulemaking. In addition, the Department estimates most small business-sized stationary sources will be below the applicability thresholds. However, the owners or operators of affected small businesses may incur minimal costs as a result of this final-form rulemaking. Overall, the Department does not anticipate that this final-form rulemaking will result in any significant adverse impact on small business-sized owners or operators.

The Department plans to educate and assist the public and the regulated community in understanding the final-form requirements and how to comply with them. The Department will continue to work with the Department's provider of Small Business Stationary Source Technical and Environmental Compliance Assistance. These services are currently provided by EMAP of the Pennsylvania Small Business Development Centers. The Department has partnered with EMAP to fulfill the Department's obligation to provide confidential technical and compliance assistance to small businesses as required by the APCA, Section 507 of the CAA (42 U.S.C.A. § 7661f) and authorized by the Pennsylvania Small Business and Household Pollution Prevention Program Act (35 P.S. §§ 6029.201—6029.209). In addition to providing one-on-one consulting assistance and on-site assessments, EMAP also operates a toll-free phone line to field questions from this Commonwealth's small businesses, as well as businesses wishing to start up in or relocate to this Commonwealth. EMAP operates and maintains a resource-rich environmental assistance website and distributes an electronic newsletter to educate and inform small businesses about a variety of environmental compliance issues.

(d) A description of any less intrusive or less costly alternative methods of achieving the purpose of the proposed regulation.

There are no less intrusive or less costly alternative regulatory provisions available.

The requirement to adopt and implement RACT requirements is Federally mandated. In accordance with sections 172(c)(1), 182(b)(2)(A) and 184(b)(1)(B) of the CAA, this final-form rulemaking establishes VOC emission limitations and other requirements consistent with the recommendations of the 2016 O&G CTG as RACT for natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, and centrifugal compressors in this Commonwealth. The Department's 2020 reanalysis has determined that the technically and economically feasible requirements for storage vessels, reciprocating compressors at well sites, and fugitive emissions components at well sites are RACT. The owners or operators of affected facilities, whether or not meeting the designation of small business, are required to control VOC emissions to meet the levels established in this final-form rulemaking. The owners or operators of many potentially affected facilities will likely not require additional control measures to comply with the RACT requirements established in this final-form rulemaking, as discussed in the response to Question 24(b).

(25) List any special provisions which have been developed to meet the particular needs of affected groups or persons including, but not limited to, minorities, the elderly, small businesses, and farmers.

No special provisions were developed. In accordance with sections 172(c)(1), 182(b)(2)(A) and 184(b)(1)(B) of the CAA, this final-form rulemaking establishes VOC emission limitations and other requirements consistent with the recommendations of the 2016 O&G CTG as RACT for natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, and centrifugal compressors in this Commonwealth. The Department's 2020 reanalysis has determined that the technically and economically feasible requirements for storage vessels, reciprocating compressors at well sites, and fugitive emissions components at well sites are RACT.

The Department has established a small business assistance program that is available to provide confidential assistance to affected small business-sized owners or operators. The owners or operators of affected oil and natural gas sources, including small business-sized entities, minorities, the elderly, and farmers are subject to the applicable requirements of this final-form rulemaking.

(26) Include a description of any alternative regulatory provisions which have been considered and rejected and a statement that the least burdensome acceptable alternative has been selected.

The Department is required under the CAA to promulgate this final-form rulemaking. No alternative regulatory provisions were considered. This final-form rulemaking is the least burdensome acceptable alternative.

(27) In conducting a regulatory flexibility analysis, explain whether regulatory methods were considered that will minimize any adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), including:

(a) The establishment of less stringent compliance or reporting requirements for small businesses.

Less stringent compliance or reporting requirements are not available exclusively for small businesses. In accordance with sections 172(c)(1), 182(b)(2)(A) and 184(b)(1)(B) of the CAA, this final-form rulemaking establishes VOC emission limitations and other requirements consistent with the recommendations of the 2016 O&G CTG as RACT for natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, and centrifugal compressors in this Commonwealth. The Department's 2020 reanalysis has determined that the technically and economically feasible requirements for storage vessels, reciprocating compressors at well sites, and fugitive emissions components at well sites are RACT. However, in this final-form rulemaking the Department also included an option for the owner or operator of a well site producing, on average, equal to or greater than 15 barrels of oil equivalent per day that also has and at least one well producing, on average, equal to or greater than 5 barrels of oil equivalent per day but less than 15 barrels of oil equivalent per day to submit to the Department a request for an exemption from the annual instrument-based LDAR requirement. The Department assumes that many of the owners or operators that would qualify for this exemption would be a small business. Owners or operators of subject small business-sized VOC emitting facilities will have to comply with the RACT requirements in this final-form rulemaking. The Department has established a small business assistance program that is available to provide confidential assistance to small businesses.

(b) The establishment of less stringent schedules or deadlines for compliance or reporting requirements for small businesses.

As explained in the response to Question 9, this final-form rulemaking is overdue to be submitted to the EPA for approval as a SIP revision. Further delay of implementation is not feasible. The Department notes that compliance dates are established throughout this final-form rulemaking that provide affected owners or operators sufficient time to identify and comply with the applicable requirements when this final-form rulemaking becomes effective upon publication in the *Pennsylvania Bulletin* as a final-form regulation. Additionally, many potentially impacted entities may already be complying with the final-form requirements as a result of implementing best management practices or already implementing instrument-based LDAR inspections. Therefore, less stringent schedules or deadlines for compliance or reporting for small businesses are not incorporated into this final-form rulemaking.

(c) The consolidation or simplification of compliance or reporting requirements for small businesses.

Recordkeeping and reporting requirements are the same for all owners or operators of affected facilities. RACT is Federally mandated. Owners or operators of subject small business-sized VOC emitting facilities will have to comply with the RACT requirements in this final-form rulemaking. The Department has established a small business assistance program that is available to provide confidential assistance to small businesses. Furthermore, for the instrument-based LDAR requirement specifically, in this final-form rulemaking the Department also included an option for the owner or operator of a well site producing, on average, equal to or greater than 15 barrels of oil equivalent per day that also has and at least one well producing, on average, equal to or greater than 5 barrels of oil equivalent per day but less than 15 barrels of oil equivalent per day to submit to the Department a request for an exemption. The Department assumes that many of the owners or operators that would qualify for this exemption would be a small business.

(d) The establishment of performance standards for small businesses to replace design or operational standards required in the regulation.

No special provisions are included for small businesses. The standards included in this final-form rulemaking are consistent with the recommendations of the 2016 O&G CTG for natural gas-driven continuous bleed pneumatic controllers, natural gas-driven diaphragm pumps, and centrifugal compressors in this

Commonwealth. The Department's 2020 reanalysis has determined that the technically and economically feasible requirements for storage vessels, reciprocating compressors at well sites, and fugitive emissions components at well sites are RACT. There are no provisions which allow a different type of standard for small businesses. The Department has established a small business assistance program that is available to provide confidential assistance to small businesses.

(e) The exemption of small businesses from all or any part of the requirements contained in the regulation.

This final-form rulemaking does not exempt owners or operators of affected small businesses. There are no provisions which allow a different type of standard for small businesses; however, it is likely that many small business owners or operators will have facilities below the applicability thresholds. See the response to Question 16 for more information. The Department has established a small business assistance program that is available to provide confidential assistance to small businesses. See the response to question 24(c) for more information on the small business impact.

(28) If data is the basis for this regulation, please provide a description of the data, explain in detail how the data was obtained, and how it meets the acceptability standard for empirical, replicable and testable data that is supported by documentation, statistics, reports, studies or research. Please submit data or supporting materials with the regulatory package. If the material exceeds 50 pages, please provide it in a searchable electronic format or provide a list of citations and internet links that, where possible, can be accessed in a searchable format in lieu of the actual material. If other data was considered but not used, please explain why that data was determined not to be acceptable.

The Department reviews its own ambient air quality ozone monitoring data for purposes of reporting to the EPA to establish attainment and maintenance of the NAAQS for all areas of this Commonwealth as discussed in the response to Question 9. The Commonwealth's Ambient Air Monitoring Network is operated in accordance with all network design, siting, monitoring and quality assurance requirements set forth in 40 CFR Part 58 (relating to ambient air quality surveillance).

The EPA's data and analysis in the Control Techniques Guidelines for the Oil and Natural Gas Industry, EPA-453/B-16-001, October 2016 is located at https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf

This final-form rulemaking uses some of the cost data and justifications provided in GP-5, GP-5A, and Exemption 38, which can be found in the TSD located at http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=19616&DocName=02%20FINAL%20TECHNICAL%20SUPPORT%20DOCUMENT%20FOR%20GP-5%20(2700-PM-BAQ0267)%20AND%20GP-5A%20(2700-PM-BAQ0268).PDF%20%20%3Cspan%20style%3D%22color%3Agreen%3B%22%3E%3C%2Fspan%3E%20%3Cspan%20style%3D%22color%3Ablue%3B%22%3E%3C%2Fspan%3E

Information on oil and natural gas well production for the 2020 reporting year can be found at the Department's Oil and Gas Well Production Report, located at https://www.depgreenport.state.pa.us/ReportExtracts/OG/OilGasWellProdReport

Air emissions for the 2020 reporting year can be found at the Department's Air Emissions Report, located at http://cedatareporting.pa.gov/reports/powerbi/Public/DEP/AQ/PBI/Air_Emissions_Report

For facility types or sources that were not reported to the Department, estimations were derived using published emissions factors or from calculated emissions factors. The Air Emission Report is compiled from the AIMS (an internal Department database) and the public-facing eFACTS database, located at https://www.ahs.dep.pa.gov/eFACTSWeb/default.aspx/default.aspx

(29) Include a schedule for review of the regulation including:

A. The length of the public comment period: 66 days

B. The date or dates on which any public meetings or hearings were held: June 23, 24, and 25, 2020

C. The expected date of delivery of the final-form regulation: Quarter 1, 2022

D. The expected effective date of the final-form regulation: Upon publication in the *Pennsylvania Bulletin*

E. The expected date by which compliance with the final-form regulation will be required: Upon publication in the *Pennsylvania Bulletin*

F. The expected date by which required permits, licenses or other approvals must be obtained: 1 year after the effective date

(30) Describe the plan developed for evaluating the continuing effectiveness of the regulations after its implementation.

The Board is not establishing a sunset date for this final-form rulemaking, since it is needed for the Department to carry out its statutory authority. The Department will closely monitor this final-form rulemaking after promulgation in the *Pennsylvania Bulletin* for its effectiveness and recommend updates to the Board as necessary.