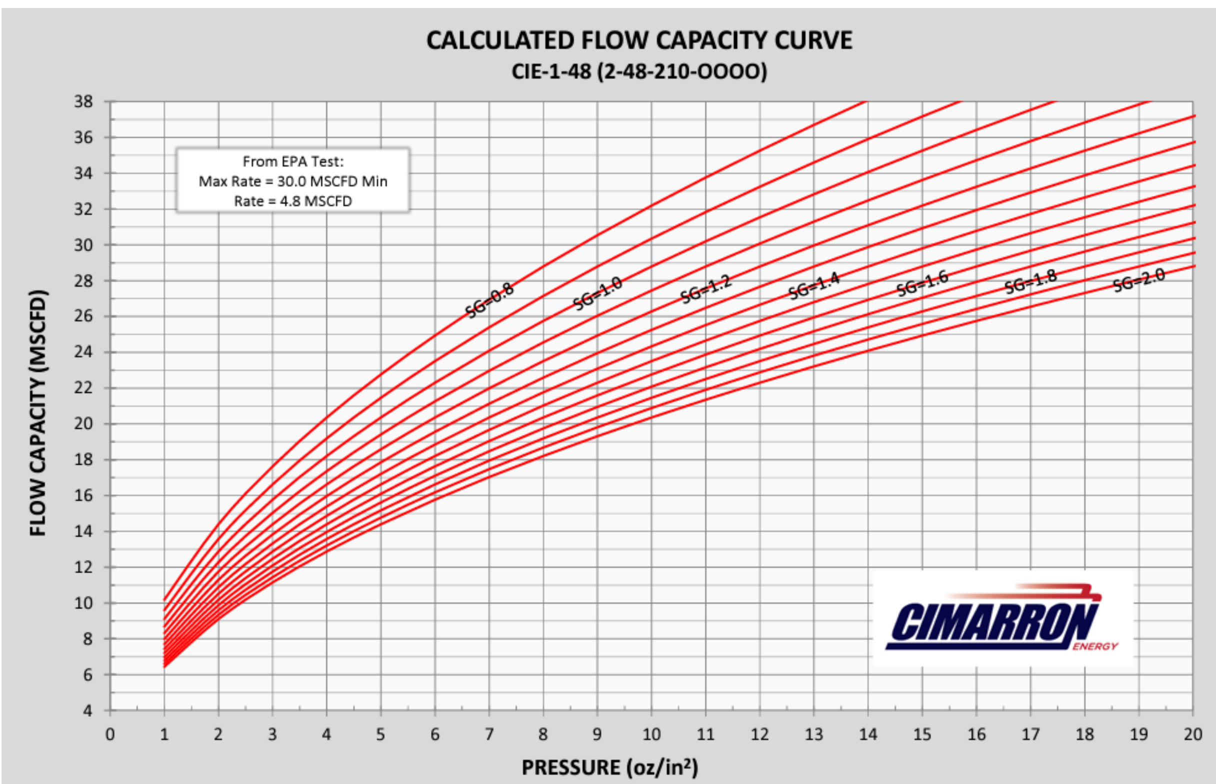
AXPC is providing this supplemental comment as a follow-up to questions raised during a March 23rd meeting with EPA staff and AXPC. We greatly appreciate the opportunity to provide further clarification on comments submitted by AXPC on February 13, 2023, regarding a number of important issues critical to industry and we hope informative for EPA's development of a workable, final rule.

Control Devices

1) Manufacturer-tested enclosed combustion devices should have the same flow monitoring requirements as other enclosed combustion devices.

AXPC understands from EPA that it did not originally propose the use of inlet pressure monitoring in lieu of flow monitoring for ECD models that are performance tested by the manufacturer due to the absence of pressure data on the manufacturer performed test. However, as shown below, manufacturers are able to provide flow capacity curves that show the relationship of inlet flow and inlet pressure from performance testing to guarantee their stated destruction efficiencies. While flow rate is measured during performance testing, it's important to know that a corresponding pressure value is tied to the measured flow rate. As a result, EPA should not limit monitoring to just flow, but should also allow for pressure as they are directly related to one another.



A flow capacity curve (as shown above) with pressure on the x-axis and flow rate on the y-axis provides a graphical representation of the relationship between the inlet pressure and the corresponding flow rate. It helps illustrate how changes in pressure can impact the flow capacity and performance of the combustion device.

It's important to note that at low inlet pressure, the flow rate may be limited, resulting in lower flow capacity and potentially reduced combustion performance. As a result, and as illustrated above, a defined minimum inlet pressure is established (1 oz/in^2 in this example) before a minimum flow rate can be provided. Based on the example flow capacity curve, it can be concluded that minimum inlet pressure is actually more impactful to ensure the stated destruction efficiency than the minimum flow rate.

Additionally, in order to verify an ECD is not operating below the minimum pressure, a valve is needed to restrict flow to the ECD before inlet pressure drops below what the manufacturer has established as the minimum inlet pressure. The pressure monitoring used for the actuation of these valves can also be applied for inlet pressure monitoring to the ECD. In this scenario, there is no need to install a meter to monitor flow rate as monitoring pressure and flow rate is repetitive and unnecessary.

As such, AXPC proposes that if an Operator can work with a manufacturer and document the corresponding operating pressures to meet their guaranteed destruction efficiency as demonstrated during the subject performance test, then pressure monitoring should be allowed.

AXPC has also learned that the current Colorado rule (Regulation 7) allows for use of pressure monitoring through submittal and approval of an "Alternative Technology and Infeasibility Request". Further, on April 4th, 2023, APCD proposed revisions to Regulation 7 to include allowance of Pressure Actuation Systems as a standard rather than an exemption. The Statement of Basis and Purpose submitted by the Division along with the proposed Regulation 7 revisions contains language explaining the purpose for adoption of the alternative to flow meters in rule language. The Division states:

> "The Commission adopted an acceptable alternative to flow meters, a pressure actuator system, for monitoring enclosed combustion devices to confirm that the enclosed combustion device is being operated appropriately. *<u>A pressure actuator system monitors pressure and provides an operator more control of their vapor control system to ensure it is operating within design parameters</u>.* This system was discussed as an alternative in 2021, but the concept was not clearly understood by the Division or operators at that time. The Division has since approved several proposals that use pressure actuator systems as an alternative to flow meters (as allowed by II.B.2.g.(iii)(C)). The Commission intends that those approvals remain valid; however, to comply with Section II.B.2.g. an owner or operator may choose to notify the Division that it rescinds its approved proposal and that it instead will adhere to the pressure actuator system requirements of II.B.2.g." [emphasis added]

AXPC recommends that this lesson learned on the benefits of using a pressure monitoring system be transferred to the current EPA rulemaking for controls regardless of whether it is manufacturer or owner tested as it is the more superior way to manage flow in these situations. Page 45 of our comment letter further discusses the issues of utilizing flow meters in this application.

AXPC also recommends that EPA reconsider the accuracy requirement of ± 2 percent or better in all cases. ± 2 percent is generally the standard for product going to sales and thus royalty and revenue generating. However, for control efficiency, maintaining operating parameters in the desired range can be achieved by adjusted alarm points to compensate for decreased accuracy making the ± 2 percent rate unnecessarily restrictive for this purpose. The requirement of ± 2 percent can only be achieved by a very limited set of metering technologies and may require operators to retrofit existing installations at significant cost with little or no discernible emissions reduction. In many cases it is not technically or commercially feasible to make these retrofits, these challenges only further compounded by present day supply chain restraints. In addition, in some operational scenarios the maximum expected flow rate may not be achieved, which therefore limits calibration and introduces inaccuracy at volumes outside the calibration range. To avoid these concerns, AXPC recommends that an accuracy requirement of ± 5 percent be allowable as this will encompass most metering technologies employed without sacrificing emission reduction. This recommended level of accuracy would then be consistent with the ±5% accuracy requirement for flare vent gas flow rates at velocities above 1 feet per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 Subpart CC (RMACT)[42]. Additional information on this issue, including potential cost information was further discussed in API's comment letter, section 5.3.

AXPC is also including below our suggested edits to the proposed rule text to properly address the stated concerns, which can also be found on page 46 and 48 of our comment letter, with an additional revision to capture the aforementioned accuracy recommendation.

AXPC provides the following suggestion for §§60.5417b(d)(viii)(D) and 60.5417c(d)(viii)(D):

> **You may use direct flow meters, monitoring of the pressure of the vapor control system, or other operating parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions, to satisfy this requirement.**

AXPC provides the following suggestion for §§60.5417b(d)(vii)(A) and 60.5417c(d)(vii)(A):

> **The continuous parameter monitoring system must measure gas flow rate or pressure at the inlet to the control device. The monitoring instrument must have an accuracy of ±5 percent or better at the maximum expected flow rate. The flow rate or pressure at the inlet to the combustion device must be equal to or greater than the minimum flow rate or pressure and equal to or less than the maximum flow rate or pressure determined by the manufacturer.**

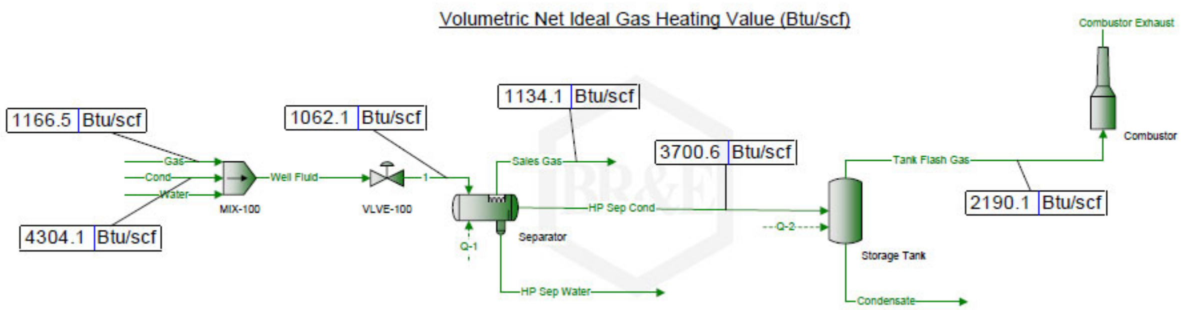
AXPC proposes that EPA revise §§60.5417b(d)(viii)(D)(*2*) and 60.5417c(d)(viii)(D) (*2*) as follows:

> **If you install and operate a backpressure preventer control valve which is set to operate remain open only at or above the minimum pressure corresponding to the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.**

2) <u>Net Heating Value</u>

Net Heating Value (NHV) Monitoring - in Section II.R.ii.b of the comments submitted by AXPC (page 43), AXPC flagged its concern that the proposed NHV monitoring for oil and gas equipment vent streams is unnecessary, and that there are more efficient approaches to satisfying EPA's concern.

As discussed, unlike a refinery, upstream operators do not use inert gases that would reduce the inherently high NHV of a vent gas stream. Due to the inherit composition of natural gas (CH_4 NHV= 910 Btu/scf) and condensate (C_3H_8 NHV= 2371 Btu/scf) and the absence of introducing inert streams, performing a net heating value performance test is unwarranted. The below flow diagram is a visual example of how the net heating value can fluctuate as streams go through phase changes. Since the streams are derived from natural gas and condensate, the NHV of the stream that goes to the combustor is significantly above the minimum values required for complete combustion (ex. 200 Btu/scf). Thus, there is little risk, and in many cases no risk, that vent gas streams will fall below the minimum NHV at any time, and certainly not great enough risk to warrant costly and onerous continuous NHV monitoring.



As stated in our letter, AXPC proposes that EPA allow operators to demonstrate the inlet stream to a combustion control device meets the applicable minimum NHV limit requirement by using a pressurized liquids analysis in combination with engineering software, similar to the example above.

Under this approach, the operator would pull a pressurized liquids sample from a separation vessel, or use a representative pressurized liquids sample, and input the sample results into engineering software configured to estimate with a high degree of accuracy the NHV.

If the engineering analysis demonstrates the NHV is within 200 Btu/scf of an applicable NHV limit, AXPC proposes that the operator must then comply with the proposed NHV continuous monitoring requirements or the alternative to continuous NHV monitoring. AXPC proposes 200 Btu/scf, as this value exceeds the 20 percent cushion of the highest potentially applicable NHV limit EPA that notes as being "well above the threshold."

This approach would achieve EPA's intent but avoid concerns of unnecessary burden and cost for an unproven solution. The use of calorimeters in the upstream oil and gas sector is still in question. The variable nature of production flowrates results in low and/or intermittent vapor control streams. Current calorimeter technology cannot accurately measure the NHV of these low and/or intermittent streams consistently over time and across varying operating conditions. Which means, in these applications, calorimeters are unlikely to yield accurate or useful data.

Additionally, calorimeter supply vendors are not even close to being able to meet this demand. Large operators may have one thousand or more flares that would require monitoring under NSPS OOOOb or EG OOOOc. Whereas one of the most prominent calorimeter manufacturers in the United States estimates today that they can only generate about 6 to 10 units per month at a cost of $70,000 to $120,000 per unit (average $100,000). The combination of equipment and labor supply shortages that would ensue will force operators into a position where compliance is simply infeasible by compliance deadlines, and all for an ineffective solution. For these reasons, AXPC strongly recommends EPA consider the alternative approach described above.

3) <u>60.18(b) Demonstrations for Initial Flare Compliance</u>

In the December 2022 proposal, EPA indicates each flare must be designed and operated according to the requirements of 40 CFR §60.18(b).[1] However, in our comments (on page 43) AXPC requested further clarification as to EPA's intent and whether the demonstration option would include the ability to use all the choices under 60.18(b)[2]. Specifically, the proposal is unclear about whether EPA intends that operators do not use the compliance option in §60.18(c)(3)(i), also referred to colloquially as V^{Max} requirements. When this topic was raised in our discussion with EPA, agency staff asked for AXPC to provide its recommendation in addition to our request for clarification. **AXPC recommends that EPA clarifies that the rule allow operators to use all options under 40 CFR §60.18(b), including the option under §60.18(c)(3)(i).**

4) <u>Method 22 Tests</u>

During our discussion, AXPC raised concerns related to EPA's proposal for monthly Method 22 tests for enclosed combustion devices (ECDs) and flares as overly burdensome, especially considering the scale of sources that will be covered. As reasonable alternative to satisfy EPA's concern while lessoning the burden (and increasing the ability for even smaller operators to comply), **AXPC recommends that operators be allowed to first evaluate and document whether the control device is smoking or not smoking at least once per week, and if the operator observes smoke, a Method 22 test will be completed within 12 hours to determine if visible emissions are occurring. Further, AXPC proposes to complete at least one Method 22 test in each semiannual period.**

Based on AXPC operator experience a combustion device that will not pass a Method 22 test will smoke frequently or continuously. Though the Method 22 test itself is only to be 15-minutes long, in practice each occurrence requires 0.5 hours to 3 hours to complete, which includes travel time, set up time, the observation period, documentation of the procedure, document quality review, organization, and filing for reporting. Considering the scale of sources that this rule will cover once fully implemented, this equates to thousands if not millions of hours observing mostly properly operating control devices. Whereas a weekly control device observation ensures frequent control device evaluation and focuses efforts where visible emissions are actually occurring.

5) <u>Semiannual Control Device Monitoring Reporting and Recordkeeping</u>

After submitting its comments on the supplemental proposal, AXPC discovered a potential semiannual reporting requirement for control device monitors and requests EPA clarify its intent. In the supplemental proposal, EPA proposes that operators prepare a site-specific control device monitoring

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[1] The proposed §§60.5412b(a)(3) and 60.5412c(a)(3) each provide, in part:
Each flare must be designed and operated according to the requirements of §60.18(b) as specified in paragraphs (a)(3)(i) through (iv) of this section.
(i) You must use Method 18 of appendix A-6 of this part to determine the NHV of the vent gas meets the requirements in §60.18(c)(3)(ii). For pressure-assisted flares, in lieu of the heating value limits in §60.18(c)(3)(ii), the NHV of the gas being combusted must be 800 Btu/scf or greater.

[2] §60.18(b) identifies that flares must comply with §60.18(c)-(f). §60.18(c)(3) provides operators a choice to adhere to heat content specifications in §60.18(c)(ii) and the maximum tip velocity specifications in (c)(4), or to adhere to the requirements in (c)(3)(i).

plan that addresses the "[o]ngoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f)," among other things.[3] §60.7(c) contains a requirement to submit a semiannual report for continuous monitoring devices subject to new source performance standards. This semiannual report must include information relating to excess emissions and monitoring system performance. **AXPC can find no analysis of the impact of semiannual reporting under §60.7(c) and requests that EPA clarify that it does not intend for operators to submit these semiannual reports.**

To the extent EPA intends for operators to submit these semiannual reports, AXPC requests that EPA include its evaluation of the impact of semiannual reporting in its regulatory impact analysis and clarify what information it intends to receive. For example, §§60.7(c) and (d) require reporting of excess emissions data obtained from continuous emissions monitoring systems; however, other than for some sweetening units, EPA's supplemental proposal does not require continuous emissions monitoring. Similarly, §60.7(f) contains recordkeeping requirements that apply only to continuous emissions monitors. Considering the already robust recordkeeping and reporting requirements contained in EPA's supplemental proposal, AXPC believes it would be inappropriate and unnecessary to apply these onerous semiannual reporting and recordkeeping requirements to monitoring devices that are not continuous emissions monitors – *e.g.,* combustion device pilot monitors.

Oil Wells and Associated Gas

AXPC greatly appreciated EPA's clarifications related to associated gas provisions, and specifically that it was not EPA's intent to imply a zero-flaring standard in the proposal's specification that associated gas must be routed to sales or beneficially used unless technically infeasible. While AXPC supports focused efforts to reduce the flaring, we appreciate that EPA recognizes there may be situations that force an operator to have to flare temporarily or due to some infeasibility outside an operator's control. In order to make clear EPA's intent clarified during our discussions, AXPC recommends the following changes in the final rule (page 20 of our comments):

1) Definition of Associated Gas

Clarify the definition of associated gas as gas evolved during initial stage of separation following production from the wellhead.

- **AXPC proposes that EPA define "associated gas" as "the natural gas evolved from hydrocarbon liquids during the initial stage of separation following production from the wellhead. Associated gas does not include natural gas associated with well completion or downhole well maintenance activities."**

2) Temporary Control of Associated Gas

Clarify that justification is not necessary for the temporary control of associated gas when the operator has designed the separator to recover and sell or beneficially use associated gas but is temporarily unavailable for reasons outside an operator's control, which includes but is not limited to equipment failure.

- **AXPC proposes that EPA remove the requirement in §§60.5377b(b)(1) and 60.5377c(b)(1) to provide a certified justification for controlling associated gas where**

[3] Proposed §§ 60.5417b(c)(2)(v); 60.5417c(c)(2)(v).

the operator complies with (a)(1), (2), (3), or (4) during normal operations and temporarily controls associated gas when the primary method of disposition is unavailable.

3) Economic and Commercial Considerations

Clarify that the consideration of material economic and commercial factors is allowed when making infeasibility determination. AXPC fully supports the concept of prioritizing the sale or beneficial use of associated gas where markets exist and connecting to them is economically viable. However, where no viable gas market exists, the lack of commercial availability and site economics to deliver gas to market is a fundamental consideration of feasibility. For example, a remote well site operator could identify the closest pipeline with capacity, but it is 100 miles away. And the cost to build, maintain, and operate the connecting pipeline may well exceed the total value of the gas that could be sold. In such a scenario, it would be technically feasible to build this connecting pipeline, but it is clearly not economically viable. Considerations of a control measure's economic viability is consistent with the World Bank's "Zero Routine Flaring by 2030" initiative and is required under Clean Air Act § 111. The need for this clarification is discussed on page 24 of AXPC's comments and with the following recommended clarification:

AXPC proposes that EPA revise the proposed §60.5377b(b), and the corresponding EG OOOOc provision, to include economic and commercial considerations as below. Note, the revisions below include revisions proposed by AXPC relating to the beneficial use of associated gas:

> **(b) If you demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section due to technical, economic, lack of commercial availability, or safety reasons in accordance with paragraphs (b)(1) through (3) of this section, you must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that meets the requirements of §60.5411b(a) and (c) and the control device must meet the conditions specified in §60.5412b(a), (b) and (c).**
>
> **(1) In order to demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section, you must provide a detailed analysis documenting and certifying the technical, economic, lack of commercial availability, or safety reasons for this infeasibility. The demonstration must address the technical, economic, lack of commercial availability, or safety infeasibility for all options identified in (a)(1), (2), (3), and (4) of this section. ~~With regard to compliance with paragraph (a)(3) of this section, another useful purpose that a purchased fuel or raw material would serve includes, but is not limited to, methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas.~~ Documentation of these demonstrations must be maintained in accordance with §60.5420b(c)(3)(ii). If the primary means of disposition of oil well associated gas is one of the options identified in (a)(1), (2), (3), and/or (4) of this section, you do not need to complete, certify, or document the detailed analysis in this section to utilize temporarily the option in §60.5377b(b)**

4) <u>Certifications</u>

We also noted in our discussion that we have serious concerns about the certification requirements for technical infeasibility demonstrations. For example, the proposal EPA discusses potential for criminal liability related to the technical feasibility demonstration for use of control devices to handle associated gas. The Clean Air Act already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals, or fails to file or maintain a document filed or required to be maintained under the CAA. Whereas what EPA has proposed here is not only duplicative of these existing assurance protections, but adds the prospect of *individual*, *personal* liability for not only fraudulent certification but also for what could be second guessing or disagreement among reviews, data discrepancies, or even just a simple mistake. While we greatly appreciate EPA's recognition that non-emitting approaches are not always practicable and the provision for an alternate path for those situations, we are concerned the potentially punitive nature of these certification requirements will be insurmountable. Not only would the certifier have to prove a negative, that a non-emitting technique is not feasible, they risk personal liability to themselves and their families if their opinion is disagreed with or if a mistake is made, which may not be of their making. It is unlikely that any individual would take such a risk and we argue it is unreasonable and unnecessary to do so. As a solution, we supported in our letter language recommended by API in comment 12.9 of their comment letter (page 106) copied also below.

> If EPA retains the requirement for case-specific certifications, EPA should revise the required certification. **The proposed regulatory text of each certification includes the following sentence: "Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete." See, e.g., § 60.5377b(b)(2). This should be revised to specify that the certification is based on "reasonably inquiry," as is required for certifications under the Title V operating permit program.** The revised certification could read as follows: "Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, …." A "reasonable inquiry" standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

<u>**Well Closure**</u>

As stated in our comments and in our meeting, AXPC supports EPA's requirement that fugitive emissions monitoring continue until the well is plugged and abandoned. However, as written EPA's proposal goes well beyond the stated purpose and raises significant questions about EPA's legal authority to implement the proposal as written. To that end, there are a number of technical and legal issues with EPA's proposal which we discuss on page 49 of our comment letter. Tangentially, as the challenge of orphaned wells has become more prominent in federal policy discussions, there remains a lot of confusion around the issue and the terminology that has led to significant misunderstandings about what has led to orphan wells, the risk today, and how to prevent/address them. Importantly, each state has different and specific rules and procedures regarding plugging and abandonment and financial assurance that all fall squarely within state's authority and expertise to regulate. For this reason, AXPC believes that EPA should rely upon the states to regulate well closures and abandonment and instead focus EPA's efforts on fugitive emissions monitoring until such time as the well has been compliantly abandoned per state regulations. **Given EPA's intent is to ensure periodic fugitive emissions monitoring occurs until a well is plugged and abandoned, a more practical, defensible solution would be to require that fugitive emissions monitoring continue until such time as the operator supplies EPA with a state approved plugging report and a final monitoring survey to confirm no emissions are occurring following plugging and abandonment.**