December 5, 2025

Submitted online via https://www.deq.louisiana.gov/public-notices
and via email to DEQ.PUBLICNOTICES@LA.GOV

RE: Comments on Draft Title V Permit No. 0180-00237-V0 and Draft PSD Permit No. PSD-LA-859 for CF Industries Blue Point, LLC's Low Carbon Ammonia Plant (Agency Interest No. 149544, Activity Numbers PER20230002 and PER20230003)

To Whom It May Concern:

Rural Roots Louisiana, the Louisiana Bucket Brigade, and the Environmental Integrity Project (collectively, "Commenters"), respectfully submit the following comments on the draft Title V Permit No. 0180-00237-V0 and draft Prevention of Significant Deterioration ("PSD") Permit No. PSD-LA-859 proposed by the Louisiana Department of Environmental Quality ("LDEQ") for CF Industries Blue Point, LLC's ("CFI") Low Carbon Ammonia Plant ("Facility") proposed for construction and operation in Modeste, Ascension Parish.

Commenters appreciate the opportunity to submit these comments, as well as LDEQ's efforts towards providing an opportunity for members of the affected community to speak at a public hearing. As described in the detailed comments below, the draft permits do not comply with the Clean Air Act, and LDEQ has not met its constitutional public trust obligations with respect to the proposed Facility. LDEQ may not approve the construction and operation of the Facility until LDEQ demonstrates that the proposed Facility will meet the requirements of the Clean Air Act ("CAA") and that LDEQ has carried out its public trust duty to ensure that "adverse environmental impacts have been minimized or avoided as much as possible consistently with the public welfare." *Save Ourselves v. La. Envt'l. Control Comm'n*, 452 So.2d 1152, 1157 (La. 1984). The proposed permits are deficient as follows:

Proposed PSD Permit No. PSD-LA-859 ("Draft PSD Permit")

- CFI must conduct a full BACT analysis for VOCs because the facility exceeds the PSD de minimis threshold based on PTE VOC emissions from the CO2 Vent, which are vastly underestimated by CFI.
- Emission estimates are not adequately supported and are underestimates, and project emissions would exceed PSD de minimis thresholds for PM10, PM2.5, and VOCs.
- CFI's NOx BACT analysis for fired sources is deficient.
- CFI's ozone impacts analysis is deficient and does not demonstrate compliance with the 8-hour ozone NAAQS.
- CFI's ammonia modeling is deficient and does not demonstrate compliance with Louisiana's ambient air standard for ammonia.
- The application materials and draft permit package have significant deficiencies.
- CFI's air dispersion modeling has several deficiencies and does not demonstrate compliance with the NAAQS.

Proposed Title V Permit No. 0180-00237-V0 ("Draft Title V Permit")

- LDEQ must revise the Draft Title V Permit to make clear what requirements apply to each unit. In particular, the Draft Title V Permit improperly incorporates the requirements of the PSD Permit and several federal regulations by reference.
- LDEQ must revise the Draft Title V permit's "Emission Rates" tables to make explicitly clear what hourly and annual emission limits apply to each unit- and what the basis for each limit is
- The Draft Title V permit does not contain testing or monitoring requirements adequate to assure continuous compliance with most of the hourly and long-term emission limits at each unit
- The Draft Title V permit impermissibly authorizes "commissioning" emissions and also impermissibly excludes these emissions from PTE

Finally, the permit record shows that CFI did not submit information necessary for LDEQ to "ensure that "adverse environmental impacts have been minimized or avoided as much as possible consistently with the public welfare," and that LDEQ has not independently evaluated what information CFI did provide. As a result, LDEQ has not satisfied its public trustee duty under Article IX, Section 1 of the Louisiana Constitution, and cannot based on the current record.

Commenters retained the services of Dr. William Battye, an environmental engineer and air modeling expert with over four decades of experience in developing and performing air pollution and exposure models, to examine the air models submitted by CFI as a part of its permit application. Dr. Battye also performed his own independent air dispersion models of ammonia and NOx. As discussed in his reports, as well as in the comments below, Dr. Battye identified numerous issues with the models submitted by CFI.

Commenters also retained the services of Dr. Petra Pless, a court-recognized expert and environmental engineer with 25 years of experience in air quality and air pollution control, for assistance with technical review of the proposed permits. As discussed in her report and in the comments below, Dr. Pless identified a number of significant issues with the permits and the technical information submitted by CFI.

Commenters have included the reports of Dr. Battye and Dr. Pless as attachments to these comments and cite directly to them where applicable. Commenters incorporate Dr. Battye's and Dr. Pless's full reports into these comments by reference. Dr. Battye's and Dr. Pless's curriculum vitae are included with their reports.

COMMENTERS

Rural Roots Louisiana is a non-profit organization founded in Ascension Parish with a mission to educate children in our community on issues relating to the environment and social justice, and to promote community stewardship and care of the earth. We have staff who reside in Modeste and others with families residing there who will be directly affected by the proposed project.

The Louisiana Bucket Brigade uses grassroots action to hold the petrochemical industry and government accountable for the true costs of pollution. The Louisiana Bucket Brigade works to create an informed, healthy society where all people can thrive.

The Environmental Integrity Project is a nonprofit organization with the mission to protect public health and our natural resources by holding polluters and government agencies accountable under the law, advocating for tough but fair environmental standards, and empowering communities fighting for clean air and clean water.

COMMENTS

I. The Draft PSD Permit Is Severely Deficient and Does Not Comply with the Requirements of the Clean Air Act.

A. CFI must conduct a full BACT analysis for VOCs because the facility exceeds the PSD de minimis threshold based on PTE VOC emissions from the CO2 Vent, which are vastly underestimated by CFI.

The Clean Air Act states that no major emitting facility may be constructed without obtaining a permit that meets the preconstruction requirements of the Act's Prevention of Significant Deterioration ("PSD") program. 42 U.S.C. 7475(a). This includes requirements that the applicant demonstrate that the Facility's emissions will not cause or contribute to any violation of the federal National Ambient Air Quality Standards ("NAAQS"), conduct a full analysis of any air quality impacts that will result from the proposed Facility, and implement best available control technology ("BACT") for each pollutant subject to regulation under the PSD program at the Facility. *Id.* at (a)(4)-(6).

The Facility falls under the "chemical process plants" industrial category, which is one of the 28 industrial categories listed under both Table 1 of LAC 33:III.509.B and 42 U.S.C. 7479(1) of the CAA. Consequently, the Facility is a "major" source for any criteria pollutant for which it has a potential to emit ("PTE") over 100 tons per year. LAC 33:III.509.A.1; *see also* 42 U.S.C. 7479(1). Louisiana's federally-approved State Implementation Plan ("SIP") defines "potential to emit" as:

> [T]he maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

LAC 33:III.509.B.

Additionally, the Louisiana SIP requires any new major stationary source to "apply best available control technology for each regulated NSR pollutant that it would have the potential to

emit in significant amounts." LAC 33:III.509.J.2. With regards to VOC emissions specifically, the Louisiana SIP defines "significant" to mean any emissions over 40 tons per year. LAC 33:III 509.B.

The permit materials state that total project increases of VOC associated with the proposed Facility (i.e., potential to emit) are 39.52 tons per year (tpy)—which comes just slightly below the PSD significance level of 40 tpy for VOCs. Based on this estimate, LDEQ determined that this Facility did not trigger PSD requirements for VOCs, and as a result CFI was not required to conduct a BACT analysis for VOCs. *See* Draft Permit Package at 6, 54, 97. The single largest source of VOC emissions at the proposed Facility is the CO2 vent, RLP 0004 (VNT-CO2), which has a proposed annual emission rate of 28.60 tons per year for VOCs in the Draft Title V Permit. Draft Permit Package at 28. The VOC emissions are attributable to the large amounts of methanol, which is both a VOC and a federal hazardous air pollutant and toxic air pollutant under Louisiana law, in the Facility's CO2 stream. 42 U.S.C. 7412(b)(1); *see also* LAC 33:III.5112, Tables 51.1 & 51.2 (list of Louisiana TAPs). According to CFI, the methanol content is associated with the catalyst used in the CO2 capture process. Draft Permit Package at 260.

Neither the PSD Permit, the Title V permit, nor the Statement of Basis explain how this 28.60 tpy figure was calculated or how it will be achieved. This omission is particularly notable given that the Title V Permit states that the maximum hourly VOC emission rate for the CO2 Vent is 80.32 lb/hour, which would yield an annual PTE of **351.8 tpy**, over 12 times the cited PTE and well above the PSD significance level.[1] (80.32 lb/hour x 8,760 hours = 703,603.2 lb/year = 351.8 tpy.)

A review of the permit application shows that CFI's calculated 28.60 tpy VOC emission rate relies upon its assumption that the CO2 stream from the CO2 absorber and CO2 flash/stripper will be captured and transported offsite (by an unidentified third party) 89% of the time. Draft Permit Package at 260 (stating "CO2 Capture Efficiency is based off CO2 from vent is being captured 89% of year" and listing "uncontrolled hours" as 963.6 hours per year). In other words, the CO2 Vent would vent to the atmosphere 11% of the time—or approximately 963.6 hours per year—and this 11% venting time results in 28.60 tpy of VOC emissions. CFI then multiplied this "uncontrolled" operating time of 963.6 hours by the "average" hourly emission rate of 59.36 lb/hour—not the maximum hourly emission rate—to yield its PTE estimate. (963.6 hours x 59.36 lb/hour = 519,993.6 lb/year = 28.60 tons per year of VOCs.)

CFI' reliance on this assumed 89% capture rate to reduce the Facility's PTE for VOCs below the significance level is both impermissible and flawed for multiple reasons:

[1] It is unclear that the "average" hourly emission rate of 59.36 lb/hour that CFI used for its PTE calculations is included in the permit as an explicit, federally enforceable limit. Unless the permit is revised to make this a limit that is enforceable as a legal and practical matter, it cannot be used as the basis for calculating PTE. Accordingly, Commenters have used the "maximum" hourly emission rate to calculate PTE. We further note that whether the 59.36 lb/hour rate or the 80.32 lb/hour rate is used does not fundamentally make a difference for purposes of determining PSD applicability, because as explained in this section, in either case CFI is well-above the PSD *de minimis* levels for VOCs because the emissions reductions CFI has attributed to CCS cannot be excluded from PTE.

1. LDEQ cannot legally exclude the VOC emissions in the Facility's waste gas stream that will purportedly be sent to an offsite, third-party carbon capture and sequestration facility from the Facility's PTE for purposes of determining applicability of major PSD requirements, because this reduction does not qualify as a "physical or operational limitation" on the design capacity of the Facility to emit VOCs; and

2. Even assuming that this could be a valid limitation on PTE, the portion of VOCs assumed for CCS, CFI has provided no evidence explaining why it is appropriate or realistic to assume that CCS will result in an 89% reduction of its VOC emissions, and a review of the rates of capture at other similar facilities—including the Air Products ammonia plant that LDEQ (mistakenly) granted a minor permit earlier this year—shows that a realistic capture rate is significantly lower.

    1. <u>The VOC reductions that CFI attributes to carbon capture and sequestration cannot be excluded from the Facility's potential to emit.</u>

As a legal matter, the reductions in VOC that CFI attributes to its assumed CCS *cannot* be excluded from the Facility's potential to emit.

As noted previously, LAC 33:III 509.B defines "Potential to Emit" as:

> [T]he maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

This definition of PTE in the Louisiana SIP mirrors EPA's PSD regulations defining "potential to emit":

> Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

40 C.F.R. 52.21(b)(4).

Thus, both Louisiana's SIP and EPA's regulations make clear that in order for a proposed limit to qualify as a limitation to a source's PTE, it must satisfy three conditions at a minimum:

(1) It must be a physical or operational limitation;
(2) That limits the design capacity of the **source itself** to emit; and
(3) It must be federally enforceable.

As discussed below, the VOC reductions that CFI attributes to its proposed use of CCS plainly does not satisfy this definition and cannot be excluded from the Facility's PTE, both because (1) the assumed 89% CCS rate is not a physical or operational limitation on the capacity of the source to emit VOCs and (2) because it is not federally enforceable as either a legal or practical matter.

a. *The assumed 89% CCS rate is not a "physical or operational limitation on the capacity of the source to emit" VOCs.*

Both the Louisiana SIP and federal regulations are clear in defining PTE to include "the maximum capacity" of a source to emit "under its physical or operational design." Louisiana's SIP also provides the following definitions related to the definition of a "stationary source" that is subject to PSD regulations. Specifically:

> *Stationary Source*—any building, structure, facility, or installation that emits or may emit any pollutant subject to regulation under this Section.
>
> …
>
> *Building, Structure, Facility, or Installation*—all of the pollutant-emitting activities that belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control), except the activities of any vessel.

LAC 33:III.509.B.[2]

A source that would ordinarily have an unrestricted potential to emit of a pollutant above major PSD thresholds may legally avoid major PSD requirements by voluntarily taking federally enforceable permit conditions which limit emissions to levels below the applicable major source thresholds. These are commonly referred to as "synthetic minor" sources (as opposed to "true" minor sources). In addition to requiring that these limits are federally enforceable, the Louisiana SIP and federal regulations specify that only a "physical or operational limitation on the capacity of the source to emit" the pollutant in question shall be treated as a part of the unit's design for purposes of calculating PTE. LAC 33:III.509.B; 40 C.F.R. 52.21(b)(4).

As explained above, the maximum capacity of the CO2 vent to emit VOCs under its physical or operational design is the stated maximum rate of 80.32 lb/hour—which would yield an annual PTE of 351.8 tons per year. (80.32 lb/hour x 8,760 hours = 703,603.2 pounds/year = 351.8 tons per year). Thus, by the plain definition of PTE, the CO2 Vent's PTE is in fact **351.8 tpy** for VOCs.[3] CFI calculated its proposed PTE emission rate of 28.60 tpy based on an assumption that the CO2 stream from the CO2 absorber and CO2 flash/stripper will be captured and transported offsite (to an unidentified third party) for carbon capture and sequestration. Though neither its application nor anything else in the permit record ever explicitly states this, it

[2] These definitions mirror the definitions for these terms found in EPA's PSD regulations. *See* 40 C.F.R. 52.21(b)(5) & (6).

[3] We reiterate that it makes no difference, for purposes of PSD applicability, whether the average hourly rate is used instead of the maximum hourly rate, as using the "average" hourly emission rate of 59.36 lb/hour would still result in a PTE of 260.01 tpy—well above the PSD *de minimis* level for VOCs.

appears that LDEQ is proposing to treat the capture and transportation of the CO2 stream like a synthetic minor limit for VOC emissions from the CO2 vent, using the assumed CCS rate as the "control device." However, this cannot serve as a valid limitation on PTE because simply sending the Facility's VOCs to an unspecified third party for disposal—a third party facility which is not a part of **this** source, is not under the control of **this** applicant, and is not subject to **this** permitting action—does not actually impose any physical or operational limit on the capacity of the proposed Facility itself to emit VOCs.[4]

The definition of PTE provides specific examples of the types of limitations that are encompassed, such as requirements to use "air pollution control equipment," or "restrictions on hours of operation or on the type or amount of material combusted, stored, or processed." LAC 33:III.509; 40 C.F.R. 52.21(b)(4). "The definition at no point suggests that the term 'physical or operational limitation' extends to restrictions on actual emissions." *United States v. Louisiana-Pac. Corp.*, 682 F. Supp. 1122, 1132 (D. Colo. 1987). On its face, this definition is clear that shipping a gas stream to a third party for off-site CCS would not qualify as either a physical or operational limit on the facility being permitted. Prior EPA guidance regarding valid limitations on PTE, as well as federal court decisions interpreting the same, similarly make this clear.

On June 13, 1989, EPA issued a memorandum entitled "Guidance on Limiting Potential to Emit in New Source Permitting" which addressed synthetic minor permits generally, the interpretation of "potential to emit," and the types of conditions in Clean Air Act construction permits which can legally limit a source's potential to emit below major PSD threshold levels ("1989 PTE Guidance").[5] The 1989 PTE Guidance broadly discusses three categories of limitations that might qualify to limit PTE, including emission limits, production limits, and operational limits.[6] With regards to the latter two categories, the 1989 PTE Guidance states:

> Restrictions on production or operation that will limit potential to emit include limitations on quantities of raw materials consumed, fuel combusted, hours of operation, or conditions which specify that the source must install and maintain controls that reduce emissions to a specified emission rate or to a specified efficiency level. Production and operational limits must be stated as conditions that can be enforced independently of one another. For example, restrictions on fuel which relates to both type and amount of fuel combusted should state each as an independent condition in the permit.

1989 PTE Guidance at 6.

---

[4] As discussed further below, at least one recent EPA order on a Title V petition to object has found problems presented by off-site controls dependent on another facility, even when both facilities are owned and operated by the permittee.

[5] The 1989 PTE Guidance memorandum is available on EPA's website at: https://www.epa.gov/sites/default/files/2015-07/documents/lmitpotl.pdf

[6] The 1989 PTE Guidance states that permits must include a production or operational limit *in addition* to an emission limitation in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment. *Id.* at 5-6.

All of the examples provided above share a common thread: they are all limitations on the on-site operation of the *applicant's facility*, which affect the design and operation of the *source* in question. Similarly, federal courts interpreting when and how emissions reductions attributable to air pollution controls can appropriately limit PTE have also made clear that this only encompasses physical equipment located at and designed into the facility. *See, e.g., Alabama Power Co. v. Costle*, 636 F.2d 323, 353 (D.C. Cir. 1979) (stating that when determining a facility's PTE, "EPA must look to the facility's 'design capacity,' a concept which not only includes a facility's maximum productive capacity… but also takes into account the anticipated functioning of the air pollution control equipment **designed into the facility**.")(emphasis added); *see also United States v. Louisiana-Pac. Corp.,* 682 F. Supp. 1122, 1132 n. 12 (D. Colo. 1987) (quoting *Alabama Power*, emphasizing the D.C Circuit's reference to equipment "designed into the facility," and noting that "[a]t no point does the opinion suggest that anything other than physical equipment should be considered" in the scope of "air pollution control equipment.").

To reiterate, CFI has based its calculated PTE of VOC emissions on the assumption that that the CO2 Vent will only be operational for 11% of the year, because the other 89% of the year CFI will transport its CO2 stream off-site, to a third-party facility which is **not** part of this source,[7] under the direct control of CFI, or subject to this permitting action. CFI's revised application does not even identify any potential CCS sites, but merely states that "[s]everal options for carbon capture and sequestration are available for development or partnership, satisfying the critical environmental need of the project and meeting the CF Industries' decarbonization strategy requirements." Draft Permit Package at 488. As Dr. Pless notes in her report, press releases from 1PointFive, a subsidiary of Occidental, indicate that 1PointFive has entered into a contract with CFI to transport and sequester the CO2 stream from the Blue Point Facility at its proposed Pelican Sequestration Hub. Pless Report at 37. CFI's most recent Form 10-Q Quarterly Report filed with the U.S. Securities and Exchange Commission appears to confirm this.[8] However, the Pelican Sequestration Hub itself has just made its final investment decision and is still currently under development. *Id.* 1PointFive's website also states that the Pelican Sequestration Hub is intended to serve a wide range of industries "across the Louisiana industrial corridor."[9] Assuming this is true, CFI's claimed PTE for the CO2 vent relies not only on a third party that is not subject to this permitting action, but a third party who has apparently not yet even received a draft permit for its own facility.[10] This means compliance with the proposed 28.60 tpy estimate is an entirely speculative exercise and dependent on a wide variety

---

[7] LAC 33:III.509.B; 40 C.F.R. 52.21(b)(5) & (6).

[8] CFI, 3Q 2025 Form 10-Q Quarterly Report (Nov. 6, 2025) at 24. ("Pursuant to a long-term offtake agreement, a joint venture between a subsidiary of Occidental Petroleum Corporation and Enbridge Inc. would then transport the CO and permanently sequester it in a Class VI well at its Pelican Sequestration Hub in Louisiana, which is currently under development.").
Available at: https://d18rn0p25nwr6d.cloudfront.net/CIK-0001324404/24f0f04c-981a-4b91-9076-0446357b6851.pdf

[9] https://www.1pointfive.com/projects/pelican-hub

[10] The Louisiana Department of Energy and Natural Resource's website indicates that DENR began its technical review of the permit application for the Pelican Sequestration Hub on March 25, 2025. DENR has not yet issued a proposed draft permit. https://www.denr.louisiana.gov/page/permits-and-applications

of factors that are not under CFI's direct control. This certainly cannot form a reasonable basis for a limit that is intended to restrict PTE below the major PSD threshold.

As discussed further in the next section, neither permit includes any condition requiring CFI to maintain an 89% CCS uptime—or any physical or operational limits on the CO2 Vent at all, such as an explicit requirement actually restricting the CO2 Vent to no more than 963.6 hours of operation per year. Even if they did, such a requirement could not serve as a valid limitation to the CO2 Vent's PTE, because it would not actually impose any physical or operational limit on the design capacity of the proposed Facility itself to emit VOCs. Accordingly, the CO2 Vent's actual annual PTE for VOCs is in fact 351.8 tpy, which is significantly above the PSD de minimis threshold of 40 tpy. LDEQ cannot issue these permits without either requiring CFI to perform a full BACT analysis for VOCs at this Facility, or revising the permits to include physical and operational limits that are permanent, federally enforceable against CFI, and designed to limit the Facility's PTE below the major PSD threshold.

b. *The assumed 89% CCS rate is not federally enforceable as either a legal or practical matter.*

CFI's attempt to rely upon third-party controls not only fails to restrict PTE as a legal matter but also presents significant barriers to enforceability as a practical matter. A limitation can only restrict PTE if "the limitation or the effect it would have on emissions is federally enforceable." LAC 33:III.509.B; *see also* 40 C.F.R. 52.21(b)(4). The 28.60 tpy "limit" is not supported by anything beyond CFI's assumed 89% CCS uptime rate for the CO2 Vent. Even if this 28.60 tpy "limit" could be considered a valid limitation on the source's PTE as a legal matter,[11] it would still not satisfy the requirements of a valid restriction to the Facility's PTE because it is not federally enforceable as either a legal or practical matter.

EPA has explained that the concept of "federal enforceability" incorporates "two separate fundamental elements that must be present in all limitations on a source's potential to emit." John Seitz, *Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act* (Jan. 25, 1995) ("1995 PTE Guidance")[12] at 2. First, EPA and citizens must have the right and ability to directly enforce the limits in question against the source; and second, the limitations must be "enforceable as a practical matter." *Id.* at 3.

The first element is usually straightforward and typically satisfied by including an explicit limit or condition in a permittee's Title V permit. However, CFI's reliance on a third party for its "control" of VOCs presents unique complications. It is not at all clear how LDEQ could fashion a limit here that is clearly applicable to and enforceable against *the permittee* specifically.

For example, EPA recently found that a gas sulfur concentration limit at U.S. Steel's Edgar Thomson Plant was likely unenforceable, because the permit stated that compliance with the limit would be demonstrated using measurements of sulfur compounds in the coke oven gas

[11] As discussed, it cannot.
[12] The 1995 PTE Guidance memorandum is available on EPA's website at: https://www.epa.gov/sites/default/files/2015-08/documents/ptememo.pdf

at U.S. Steel's nearby Clairton plant. *In the Matter of United States Steel Corporation, Edgar Thomson Plant Permit No. 0051-OP23*, Order on Petition No. III-2023-15 (Feb. 7, 2024) ("Edgar Thomson Order")[13] at 20. The state's reasoning was that it made sense for the measurements to be made at the Clairton plant, because the Clairton plant produced the gas in question used at Edgar Thomson and both facilities were owned and operated by U.S. Steel. *Id.* Though EPA acknowledged that there was nothing inherently problematic with this rationale, it still found that this permit term was likely unenforceable because the compliance method was not enforceable *against the Edgar Thomson facility* specifically:

> As written, the Permit's statements that "[t]he permittee shall measure the sulfur concentration of all coke oven gas used for combustion or flaring at the facility" and "coke oven gas measurements are taken at the Clairton Plant" appear to be in conflict. Although the Clairton and Edgar Thomson Plants are both currently owned by U.S. Steel, the *permittee* here is the Edgar Thomson Plant. It is not clear that the permittee can itself satisfy this condition as written, as nothing in the Permit or permit record indicate that the Edgar Thomson Plant (or representatives of this facility) have the authority or ability to directly measure sulfur concentrations in the coke oven gas produced at the Clairton Plant. Overall, the permit term, as written, does not clearly impose obligations that the permittee itself can fulfill, and thus appears to be potentially unenforceable against the permittee.

Edgar Thompson Order at 20.

Here, the two facilities are not even under the same ownership and control. Thus, LDEQ must ensure that any limits and methods to assure continuous compliance with those limits—including testing, monitoring, and reporting requirements—are fully within the authority of the CFI Blue Point permittee specifically to control, and fully enforceable against the CFI Blue Point permittee.

In order to be enforceable as a practical matter, all limits "must be of sufficient quality and quantity to ensure accountability," because if limits are "incomplete or vague or unsupported by appropriate compliance records, enforcement by the States, citizens and EPA would not be effective." 1995 PTE Guidance at 5. In general, for a limit to be enforceable as a practical matter the permit's provisions must specify:

(1) A technically-accurate limit and the portions of the source subject to the limitation;

(2) The time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and

(3) The method to determine compliance including appropriate monitoring, recordkeeping, and reporting.

Id. at 6.

[13] The Edgar Thomson Order is available on EPA's website at: https://www.epa.gov/system/files/documents/2024-02/us-steel-edgar-thomson-order_02-07-2024.pdf

The Draft Title V Permit as currently drafted fails to satisfy any of the above conditions.

First— for a limit to be federally enforceable, there must be a limit in the first place. As noted previously, in the Revised Application CFI relied upon an assumed 89% CCS uptime rate as the basis for the calculated 28.60 tpy annual VOC emission rate for the CO2 vent—and in fact, the 28.60 tpy limit *cannot* be achieved *unless* CFI maintains an 89% CCS uptime rate at all times—neither the PSD permit or the Title V permit contain even a general condition requiring that CFI use CCS at all, let alone a requirement to maintain 89% CCS uptime. In fact, carbon capture is not referenced a single time in either permit, LDEQ's Statement of Basis, or even the process descriptions of the Facility or the CO2 Vent—a highly unusual omission, given that CFI's application makes clear that the assumed 89% CCS uptime rate is the *only* reason that its calculated emissions remain below the PSD major threshold levels.

In fact, both permits contain barely any requirements related to the CO2 Vent at all. The permits contain the following emission limits applicable to the CO2 Vent:

- For CO emissions:
    - A maximum hourly emission rate of 6.12 lb/hour, and an annual emission limit of 2.95 tpy. PSD Permit at 34; Title V Permit at 26.

- For CO2e emissions:
    - An annual emission limit of 289,272 tpy. PSD Permit at 34; Title V Permit at 25.

- For VOC emissions:
    - A maximum hourly emission rate of 80.32 lb/hour,[14] and an annual emission limit of 28.60 tpy. Title V Permit at 26.

The Title V permit only contains three specific conditions applicable to the CO2 Vent, which generally require:

> **Title V Permit, Condition 157**: requires limited recordkeeping for equipment and operational data. Because LDEQ has apparently determined that this Facility is exempt from the requirements of LAC 33:III.2115, CFI is only required to report information to the extent as may be needed to demonstrate that the criteria for this exemption are being met. LAC 33:III.2115.L.4.
>
> **Title V Permit, Condition 158**: authorizes alternate annual emission limits of 26.80 tons of CO, 260.01 tons of VOC, and 246.60 tons of methanol that apply during the Facility's one-year commissioning period.[15]

[14] As discussed in Section I.A of these comments, as currently drafted it is not apparent whether the "average" emission rate of 59.36 lb/hour is intended to be an hourly limit at all. (And if so, it is certainly not an enforceable one). It is also not clear whether the "maximum" hourly emission rate of 80.32 lb/hour is intended to be a limit—but for purposes of this comment, we have assumed it is.

[15] These annual emission limits appear to be the annual PTEs for each pollutant at their respective "average" emission rates. As discussed previously, these are required to be calculated using the identified *maximum* hourly emission rates instead.

Title V Permit, Condition 159: stating that BACT for CO and CO2e emissions "is determined to be proper design and maintenance according to the manufacturer's specifications of the CO2 compressor, CO2 absorber, and CO2 flash/stripper."

The emission limits and three specific conditions above are the only requirements applicable to the CO2 Vent under either permit. Notably missing are any requirements that would actually ensure that the CO2 Vent is meeting a VOC emission limit of 28.60 tpy, or enable regulators or citizens to determine and enforce against CFI's noncompliance with this limit—such as (but not limited to) a requirement to maintain its assumed CCS uptime of 89%, to limit the maximum throughput or annual hours of operation for the CO2 Vent, or to periodically test, monitor, or report emissions of VOCs actually emitted as a part of the CO2 stream. EPA has made clear that when a permit contains no explicit limit on utilization or hours of operation, "the potential to emit calculation should assume operation at maximum design or achievable capacity (whichever is higher) and continuous operation (8760 hours per year)." 1989 PTE Guidance at 7.

An annual VOC limit of 28.60 tpy alone is not enforceable as a practical matter. It is precisely the type of "blanket" tpy restriction that the *Louisiana-Pac. Corp* court held did not constitute, by itself, a valid restriction to a facility's PTE. *See United States v. Louisiana-Pac. Corp.*, 682 F. Supp. at 1132-3 (holding permit conditions limiting CO emissions to 78 tpy and VOCs to 101.5 tpy alone, unsupported by more specific requirements, could not be used to limit PTE because they did not meet the definition of a "physical or operational limitation" and were not enforceable). The *Louisiana-Pac. Corp* court emphasized that a "fundamental distinction" between the types of limitations expressly included in the definition of PTE (such as restrictions on hours of operation or on the amount of material that may be combusted or produced) and "blanket" tpy restrictions is that the former are conditions which are typically relatively easy to enforce and verify through records. *Louisiana-Pac. Corp.*, 682 F. Supp. at 1133. "In contrast, compliance with blanket restrictions on actual emissions would be virtually impossible to verify or enforce." *Id.* This is precisely why EPA has stated that all permits "must contain a production or operational limitation **in addition** to the emission limitation in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment." 1989 PTE Guidance at 5-6 (emphasis added).

A review of each of the three components of practical enforceability demonstrates precisely why blanket restrictions such as the one proposed here are unenforceable as a practical matter.

First—it is not clear that the proposed 28.60 tpy limit is technically accurate. Any standard set must be "technically sufficient to provide assurance to EPA and the public that they actually represent a limitation on the potential to emit" of the source in question. 1995 EPA PTE Guidance at 8. This means that the permittee must show that any presumed control efficiency is technically accurate, and the permit must include "specific parameters as enforceable limits to assure that the control efficiency will be met." *Id*.

Because nothing in the permit record provides a basis for the 28.60 tpy annual emission limit, or explains how CFI will meet this limit, it is impossible to assess its reasonableness or accuracy. This is especially the case because the apparent sole basis for the limit appears to be

CFI's assumption that it will maintain 89% CCS uptime, which presumably depends on a wide variety of factors—ranging from potential downtime necessitated by maintenance to CFI's own equipment, and actual availability and capacity of hypothetical third-party CCS facilities—that are not discussed at all anywhere in the permit record. Across multiple applications and addendums in the permit record, CFI has never provided any specific information regarding the grounds for its assumed capture rate or its reasonableness, which is especially concerning given that its initial application assumed a much lower 78.4% CCS capture efficiency rate.

CFI has not provided any evidence supporting the reasonableness of its 89% capture efficiency estimate, and likely cannot. This estimate should be given no credence, particularly given that recent evidence from other similar facilities—including one facility permitted just earlier this year by LDEQ—shows that an assumed 89% CCS capture rate is wildly unrealistic. As LDEQ is aware, LDEQ is currently in the process of issuing a revised major Title V and PSD permit for the nearby Air Products Blue Energy facility, which was mistakenly permitted just earlier this year as a minor source, precisely because Air Products was **not** able to achieve the capture efficiency that it had represented in its application. Air Products stated in its original application that it would achieve a 95% capture efficiency, while the revised application reflects a much more realistic 75% capture efficiency.

Additionally, the VOC emissions released from the CO2 Vent (and several other units at this Facility) are highly dependent on the methanol content of the CO2 gas stream. Much like the assumed CCS uptime rate, the assumed methanol content of the CO2 gas stream has changed significantly since CFI's initial application. *Compare* Draft Permit Package at 770 (initial application stating projected average methanol concentration of 40 ppm wt%) *with* Draft Permit Package at 260 (revised application stating projected average methanol concentration of 92 ppm wt%). Nothing in the Revised Application acknowledges or explains the reasons for this dramatic change in methanol concentration, and neither application includes an explanation as to how CFI arrived at these estimated ppm values, leaving it unclear as to whether these estimates are reliable and how much variation in methanol ppm might be expected during normal operation. This is especially concerning given that CFI's Revised Application notes that methanol formation is expected to be higher during the first year of initiating the catalyst cycle—up to 100 ppmw—and then reduce to the "estimated yearly average" concentration of 92 ppmw. Draft Permit Package at 260. Without any further information, it is impossible to assess how reliable these estimates are. This is important because if average methanol ppm levels end up exceeding 92 ppm, VOC emissions will also exceed their permitted levels.

Second—to ensure that a limit is practically enforceable, the permit must explicitly specify a time period for the limitation—generally, hourly, daily, or monthly—that will readily allow for demonstration of compliance. EPA has emphasized that as a general rule, the time period over which limitations extend should be as short-term as possible and should generally not exceed one month, and in no case should exceed an annual limit rolled on at least a monthly basis. 1989 PTE Guidance at 9. The Title V Permit simply states an annual VOC emission limit of 28.60 tpy. Nothing in the permit states that compliance with this limit will be based on a rolling monthly average, or contemplates that compliance will be measured or determined on any other timeframe shorter than a year. (Again, because the permit lacks any monitoring or testing provisions at all for the CO2 Vent). This is precisely the type of limit that both EPA and EPA's

Office of Inspector General have noted cannot satisfy the practical enforceability requirement. 1989 PTE Guidance at 10 (stating that "under no circumstances would a production or operation limit expressed on a calendar year annual basis be considered capable of legally restricting potential to emit."); EPA Office of Inspector General Report No. 21-P-0175 (July 8, 2021) at 11[16] (discussing numerous examples of state-issued Title V permits which improperly labeled annual emission limits as TPY rather than on a rolling annual basis, without clearly stating that these limits were to be based on a 12-month rolling total or provide corresponding short-term limits (such as hourly limits) that would make the limit easier to enforce.).

Finally, a permit limit is not enforceable unless the permit includes a method of determining and assuring continuous compliance with the limit, including appropriate monitoring, recordkeeping, and reporting requirements. 1989 PTE Guidance at 6. As noted above, the permits do not include *any* monitoring, testing, or reporting requirements *at all* for the CO2 Vent, aside from Title V Permit, Condition 157, which only requires CFI to report limited information for the purpose of justifying its claimed exemption from the requirements of LAC 33:III.2115. The lack of any operational limits, or associated monitoring or testing requirements, designed to actually ensure that annual VOC emissions from the CO2 Vent remain below 28.60 tpy—such as an explicit requirement that CFI limit operation of the CO2 Vent to no more than 963.6 hours of per year, or to periodically test and report actual VOC emissions emitted from the vent or methanol content in the CO2 stream—renders the 28.60 tpy "limit" meaningless. These deficiencies are especially problematic because CFI has provided no evidence suggesting an assumed 89% capture rate is reasonable, and in fact the evidence from other ammonia plants—including the nearby Air Products facility permitted earlier this year by LDEQ—shows that an 89% efficiency rate is very unlikely to be achievable in practice.

2. <u>CFI has provided no evidence supporting the reasonableness of its assumed 89% capture efficiency, and a review of the rates at other similar facilities shows that a realistic capture rate is significantly lower.</u>

CFI and LDEQ bear the burden, as the permittee and permitting authority respectively, of demonstrating the reasonableness of the proposed permit terms. CFI has provided no evidence showing that an 89% capture rate is reasonable or achievable in practice. As noted previously, CFI's application does not even identify any potential CCS sites. CFI's estimate is entirely speculative and should be given no credence at all—especially since a review of the capture rates at other blue ammonia plants, including the Air Products ammonia plant that LDEQ authorized earlier this year, shows that a realistic capture rate is significantly lower than CFI's estimate.

As Dr. Pless states in her report, several recently proposed blue ammonia plants with pending permit applications have demonstrated a much lower CCS uptime than CFI's 89% number. For example, Enbridge assumed a 75% uptime for the third-party CCS infrastructure they propose to use for their Ingleside Blue Ammonia Plant (aka Ingleside Clean Ammonia Partners) located in Ingleside, Texas.[17]

---

[16] EPA OIG. *Report No. 21-P-0175: EPA Should Conduct More Oversight of Synthetic Minor-Source Permitting to Assure Permits Adhere to EPA Guidance*. (July 8, 2021). Available at: https://www.epa.gov/system/files/documents/2021-07/_epaoig_20210708-21-p-0175.pdf

[17] Enbridge Ingleside Blue Ammonia Plant Application, Pless Report Exhibit 13 at 27, 174.

Perhaps the most directly relevant example, however, is Air Products Blue Energy LLC's Blue Energy Facility, which is also a blue ammonia plant utilizing autothermal reforming ("ATR") located in Ascension Parish that LDEQ (mistakenly) granted a minor source permit earlier this year. In its initial application for a minor source permit, Air Products had warranted that the facility would be below all major Title V and PSD permitting thresholds based on an assumed CCS uptime rate of 95%.[18] Despite receiving numerous public comments noting that this assumed CCS uptime rate was unrealistic and impossible to achieve in practice, LDEQ declined to address these comments or establish any minimum CO2 capture rate based in part on the grounds that the "potential criteria pollutant and TAP emissions" were not dependent on the capture rate, and "[o]nly CO2 emissions would increase if the target capture efficiency were not achieved," and issued Air Products a minor source permit. *See, e.g.*, LDEQ Air Products Response to Comment Nos. 14, 23, 35. Barely three months after LDEQ issued this minor source permit, Air Products submitted a new application for major Title V and PSD permits, noting that it had revised its CCS uptime assumption downwards to 75%, resulting in a significant increase in emissions of multiple criteria pollutants and TAPs above the major Title V and PSD threshold levels.[19] This downward revision to Air Product's CCS assumption was unsurprising. As public comments provided on the Air Products minor source permit noted, a review by the Institute for Energy Economics and Financial Analysis indicates that there have been no commercial-scale autothermal reforming hydrogen plants in the world that have been shown to capture the CO2 they create at these rates.[20]

LDEQ must not repeat the same mistake that it made with the Air Products facility. A review of capture rates achieved in practice at other facilities, including LDEQ's own recent experience with Air Products, shows that CFI's claimed 89% CCS uptime rate is unrealistic and unachievable in practice.

3. CFI's assumed CCS rate is unrealistic and likely unachievable in practice, suggesting that this may be an impermissible sham permit.

LDEQ must view CFI's claimed 89% CCS uptime rate with particular skepticism, given that any deviation from this rate would result in an exceedance of the PSD significance threshold level. As Dr. Pless notes in her report, if CFI had assumed a CCS rate of 88.8%—just 0.2% less than its current assumed rate—the Facility would have exceeded the VOC PSD threshold.

[18] Air Products EAS, pdf. 11-13 EDMS 14205410, https://edms.deq.louisiana.gov/app/doc/view?doc=14205410.
[19] Air Products Blue Energy PSD/Title V Application at 2.
[20] David Schlissel & Anika Juhn. *Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution*. Institute for Energy Economics and Financial Analysis (2023), PDF at pg. 7.
Available at: https://ieefa.org/resources/blue-hydrogennot-clean-not-low-carbon-not-solution

Table 1 Comparison of 89% CCS uptime rate v. 88.8%.

	Applicant Scenario	Alternative Scenario
CCS Uptime Assumption (% of year)	89.0*	88.8
Time Venting to Atmosphere (% of year)	11.0	11.2
CO2 Vent - Hours Venting (hr/yr)	963.60	981.12
CO2 Vent - Hourly VOC Emission Rate (lb/hr)	59.362**	59.362**
CO2 Vent - Annual VOC Emission Rate (tpy)	28.60	29.12
All Other Sources - Annual VOC Emission Rate (tpy)	10.92	10.92
Facility - Annual VOC PTE (tpy)	39.52	40.04
Exceeds VOC PSD De Minimis Threshold (40 tpy)	No	Yes

*According to footnote 1 on pg. 260 in the Draft Permit Package, "CO2 Capture Efficiency [89%] is based off CO2 from vent is [sic] being captured 89% of the year"
**Average VOC emission rate for CO2 vent from the Draft Permit Package at 260

LDEQ must take particular care to ensure that the 89% assumed CCS uptime rate is reasonable and actually achievable in practice, given that this is the precise level needed in order for CFI to remain below the PSD significance threshold for VOC emissions. LDEQ should be especially skeptical of CFI's claimed rate, given that the permit record shows that CFI has revised its assumed CCS uptime rate upwards twice in the course of this permitting action—in both cases with no explanation, and to the precise levels necessary to ensure that VOC emissions remain below the PSD significance threshold.

In its original permit application submitted on September 11, 2023, CFI calculated facility-wide PTE emissions of VOCs of 39.43 tpy. *See* Draft Permit Package at 862. This was based on an assumed CCS capture rate of 78.4%. Draft Permit Package at 1036. On October 9, 2023, Corbet Mathis—LDEQ's permit writer for this Facility—emailed CFI to inform the company of multiple issues with the application that needed to be addressed. Draft Permit Package at 673. One of the critical issues that Corbet identified was that CFI's PSD applicability analysis had failed to include projected VOC emissions from the General Condition XVII activities and insignificant activities. *Id.* Including these emissions would have added a total of 1.63 tpy of VOCs to the total PTE—1.38 tpy from the General Condition XVII activities, and 0.25 tpy from the insignificant activities[21]—which would have put the Facility's total PTE for VOCs at 41.06 tpy, thereby triggering major PSD requirements for VOCs. Accordingly, Corbet requested that CFI provide a PSD review and BACT analysis for VOCs for the Facility. Draft Permit Package at 673

In response to Corbet's email, CFI provided an update to the application that included the VOC emissions for the General Condition VXII and insignificant activities in the project's PTE—but also "updated" the CO2 vent emission rate calculations. Draft Permit Package at 673.

[21] The original application did not include emissions from insignificant activities. However, they were subsequently estimated at 0.25 tpy for VOCs in CFI's November 2023 Update to its initial application.

Specifically, this "updated" application revised the assumed CCS capture rate upwards from the 78.4% rate used in the original application to 78.9%. Draft Permit Package at 770. This small change in the assumed CCS rate resulted in a decrease in the Facility's total VOC tpy of 1.58—which was roughly the amount of the projected increase to CFI's PTE that would have resulted from including the General Condition VXII and insignificant activities and was just enough to keep the Facility below the PSD threshold. This change in emissions from the slightly increased assumed CCS rate was the only change in VOC emissions in the November 2023 update. *Compare* VOC emissions table at page 60 of November 2023 Update *with* VOC emissions table at page 151 of Initial Application. Neither the November 2023 updated permit materials nor CFI's email to Corbet Mathis accompanying the submission provided any rationale or explanation at all for this change in the assumed CCS rate.

In February of 2025, CFI submitted a revised application, which forms the basis for the current PSD and Title V permits at issue. The Revised Application states that the primary reason for the revised application was to reflect that CFI had chosen to replace the steam methane reforming ("SMR") process proposed in the original 2023 application with an autothermal reforming ("ATR") process instead. *See* Draft Permit Package at 111. The Revised Application indicated that the new process design would result in a proposed ammonia production rate of 4,400 tons per day (tpd), as opposed to the 4,000 tpd rate originally proposed. *Id.* What the Revised Application did not explicitly note was that the proposed change in the process used apparently also resulted in a **significant** increase in methanol content in the Facility's CO2 stream—more than a 100% increase from 40 ppm to 92 ppm—resulting in a large increase in both projected annual methanol emissions and VOC emissions for multiple units. *Compare* Draft Permit Package at 770 (initial application stating projected average methanol concentration of 40 ppm wt%) *with* Draft Permit Package at 260 (revised application stating projected average methanol concentration of 92 ppm wt%). The Revised Application also revised the assumed CCS capture rate upwards once again to the current 89%—which, as discussed above, is the exact uptime rate needed to keep this Facility just below the PSD threshold and avoid a BACT analysis for VOCs.

Because the Revised Application does not acknowledge or explain the reasons for this jump in methanol concentration, Commenters cannot be certain as to the precise technical reasons underlying this significant difference. Commenters assume that something inherent to the ATR process proposed in the Revised Application results in an increased methanol content in the CO2 stream. The key takeaway, however, is that the increase in methanol content would have easily taken CFI significantly above the PSD de minimis threshold, which CFI managed to avoid by revising its assumed CCS rate upwards to 89%—the precise level needed to remain below the threshold. As with the revised CCS uptime assumption in the November 2023 updated permit materials, CFI's revised application did not provide any reasoning or explanation for this significant change in the assumed CCS rate.

As rates at other facilities show, the claimed 89% rate is unlikely to be achievable in practice. It is extremely important for LDEQ to ensure that any assumed CCS rate is realistic at this early stage. EPA has long-recognized the risk of so-called "sham" PSD permits—essentially, synthetic minor permits where a source takes operating restrictions that purport to keep the source below PSD de minimis levels, but which represent operating levels that the permittee may

not intend to adhere to long-term. 1989 PTE Guidance at 10. In such cases, a source is generally attempting to expedite construction by securing a minor source status, thereby avoiding the lengthier substantive and procedural requirements of major PSD, and then seek a revision to those limits after completion of construction and commencement of operation. *Id.* at 13. Louisiana's SIP contains a specific prohibition against such permits, and states that:

> At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of Subsections J-S of this Section shall apply to the source or modification as though construction had not yet commenced on the source or modification.

LAC 33:III.509.R.4.[22]

In other words, in the event a source originally permitted as a synthetic minor for a pollutant later becomes a major source due to a relaxation of any limits in the original permit, the immediate and automatic consequence is that the applicant must undergo all the requirements of the major PSD program. However, we note that retroactive application of BACT and other PSD requirements are not the *only* potential consequences for an erroneous synthetic minor permit, and that CFI should be incentivized to get this correct. EPA has specifically noted that if it believes that a permit was in fact a "sham" permit, and that the source likely intended to operate at major source levels, it may also pursue enforcement action against the facility. 1989 PTE Guidance at 13. Whether or not EPA decides to pursue enforcement against the facility depends on whether the available evidence suggests that the source acted in good faith in taking the synthetic minor limit in question. *Id.* at 12.

It is vitally important for a permitting agency to guard against potential "sham" permits, because they are not merely a paperwork error and can have significant practical and environmental consequences. For example, one of the obvious concerns related to sham permitting is the practical consequence that a sham permit may have on the BACT analysis and selection of pollution control technologies based on the *timing* of the PSD major source applicability determination. Specifically, when evaluating BACT at a source, a facility is allowed to weigh the relative *cost* of implementing a specific control measure at the facility against its emission reduction benefits. As a general rule, it is typically much more expensive to retrofit existing equipment with pollution control equipment than it is to construct new equipment that already has said controls built-in to the design—meaning that an older facility requiring retrofits may be treated more leniently under BACT's cost-benefit analysis, and ultimately may be permitted to install much less stringent controls than it would have been otherwise required to do had it been correctly permitted in the first place. The fact that there may be perverse incentives for delaying a BACT analysis is precisely why it is so important for a permitting authority to ensure that a facility is appropriately permitted in this first instance.

[22] This language is more or less identical to 40 C.F.R. 52.21(r)(4), which is EPA's PSD regulation similarly forbidding sham permits.

CFI has never provided any information supporting the reasonableness of its assumed 89% CCS uptime rate; CFI's assumed 89% rate is significantly higher than the rates assumed at other ammonia plants and appears almost certainly unachievable in practice; and the permit record shows that CFI has revised its assumed CCS rate upwards twice, both times without any reasoning or explanation showing the reasonableness of the assumed rate. For all the reasons above, it is clear that CFI Blue Point actually exceeds the VOC PSD *de minimis* threshold, and consequently, LDEQ must require CFI to conduct a BACT analysis for VOCs, as well as redo their air modeling analysis for ozone to account for the significantly higher VOC emissions.

B. CFI's emission estimates are not adequately supported and are underestimates; project emissions exceed PSD de minimis thresholds for PM10, PM2.5, and VOCs, requiring CFI to perform a BACT analysis for all three.

1. <u>The use of AP-42 emission factors may underestimate the Facility's true potential to emit.</u>

As mentioned in Dr. Pless's report, CFI almost exclusively relied on AP-42 emission factors to estimate PM10, PM2.5, and VOC emissions.[23] This was done even though EPA considers the use of AP-42 emission factors to be the least accurate method for estimating emissions.[24] Furthermore, EPA issued an Enforcement Alert in 2020 warning against their use to set permit limits.[25] AP-42 emission factors are based on average emission rates across multiple sources and were intended for use in area-wide emission inventories.[26] When applied to individual sources, they may over- or underestimate emissions since they are based on an average.[27] In other words, if AP-42 emission factors are the sole method for setting and enforcing emission limits, each emission unit has about a 50/50 chance of not being in compliance. Furthermore, AP-42 emission factors do not account for short-term fluctuations in emission rates, and as such, their use increases the likelihood of exceeding short-term permit limits.[28] Consequently, CFI's use of AP-42 emission factors may result in the Facility's potential to emit being underestimated. Had a more accurate method been used, such as vendor-provided emission factors based on stack testing of similar units, the Facility's PM10, PM2.5, and/or VOC emissions may have exceeded the respective PSD *de minimis* threshold, meaning CFI would be required to conduct a BACT analysis and air quality modeling for these pollutants.

2. <u>CFI's methodology for calculating PM10, PM2.5 and VOC emissions from the steam superheater and fired process heater is unsupported and substantially underestimates emissions.</u>

As Dr. Pless notes in her report, CFI estimated PM10, PM2.5, and VOC emissions from the steam superheater and fired process heater by applying AP-42 emission factors for boilers and furnaces combusting pipeline-quality natural gas to the methane component of the various

[23] Pless Report at 17.
[24] *Id.*
[25] *Id.* at 18.
[26] *Id.*
[27] *Id.*
[28] *Id.* at 19.

fuel streams going to these two emission units.[29] In addition to general issues with the use of AP-42 issues mentioned above and in Dr. Pless's report, this methodology is flawed because it does not consider the contribution of other fuel stream components to emissions.[30] For example, the pilot gas stream includes C2+ hydrocarbons (i.e., hydrocarbons with two or more carbon atoms), but CFI's calculations do not consider PM10, PM2.5, or VOC emissions from the combustion of these compounds.[31]

Furthermore, there are significant discrepancies between the PM10, PM2.5, and VOC emissions estimated for the Project and similar, recently permitted facilities.[32] As mentioned in Dr. Pless's report, the recently permitted Ascension Clean Energy Project estimates PM10/PM2.5, and VOC emissions for each 3,967 tpy ammonia train to be 15.83 tpy and 3.18 tpy, respectively.[33] These estimated emissions are significantly higher than the estimated PM10/PM2.5 and VOC emissions for the 4,400 tpy ammonia train at CF Industries Blue Point (PM10/PM2.5: 1.07 tpy, VOC: 0.78 tpy).[34] The fact that per train emissions are so much higher for Ascension Clean Energy, despite the train's production capacity being only 90% of the production capacity of the train at CF Industries Blue Point, raises significant concerns, especially since both facilities are using the same ATR technology (Topose SynCOR^{TM}).[35] Ascension Clean Energy's estimated emissions were calculated using vendor-provided emission factors, which are preferable to AP-42 emission factors, and had CFI used this more accurate methodology, the estimated PM10/PM2.5 and VOC emissions for the steam superheater and fired process heater would be 24.3 tpy and 40.95 tpy, respectively.[36] This would cause an exceedance of the PSD *de minimis* thresholds for these pollutants, and consequently, CFI should have been required to do a BACT analysis and air dispersion modeling for these pollutants.

3. <u>CFI's methodology for estimating fugitive emissions is unsupported and likely substantially underestimates emissions.</u>

As stated in Dr. Pless's report, CFI estimated fugitive ammonia emissions from the Ammonia Plant by applying average emission factors for the synthetic organic chemical industry (SOCMI) multiplied by an unjustified "molecular weight factor" of 0.2429.[37] There is no reference to using this "molecular weight factor" in EPA's guidance document, making this approach unsupported.[38] Furthermore, as noted by Dr. Pless, CFI's estimated component count for the Ammonia Plant, which is based on an unnamed "similar size ammonia unit owned by CF," is far less than the estimated component counts for similar facilities.[39] Additionally, CFI

[29] *Id.* at 23–25.
[30] *Id.* at 25–26.
[31] Draft Permit Package at PDF pg. 234.
[32] Pless Report at 19–22.
[33] *Id.* at 21.
[34] *Id.*
[35] *Id.* at 21–22.
[36] *Id.* at 22–26.
[37] Id. at 27–28, 30.
[38] *Id.* at 30.
[39] *Id.* at 28–30.

failed to estimate CO, VOC, and TAP emissions from the Ammonia Plant.[40] CFI also failed to estimate fugitive emissions from the ammonia storage tanks and pipeline distribution system and likely underestimated fugitive emissions from the marine terminal.[41] Together, the fugitive emissions for this Facility are unsupported and likely underestimated.

4. CFI provides no justification for estimate of ammonia emissions from line clearing.

As Dr. Pless states in her report, CFI claims that line clearing qualifies as a General Condition XVII activity because the estimated ammonia emission rate (0.59 tons/year) is below the Minimum Emission Rate (MER) for ammonia (0.60 tons/year).[42] However, CFI provides no justification (i.e., calculations) for their estimate of ammonia emissions from line clearing.[43] Instead, CFI simply states in the revised application that the maximum ammonia emissions from line clearing will be 0.59 tons/year,[44] which is just under the ammonia MER of 0.60 tons/year.[45] LDEQ must require CFI to provide adequate justification (i.e., calculations) to support all of their emission estimates.

5. CFI provides inconsistent information about cooling towers for this project; cooling tower emissions are unsupported and likely underestimated.

As Dr. Pless mentions in her report, CFI's February 7, 2025, revised application references "cooling towers," but identifies and calculates emissions for only one cooling tower and two evaporative condensers.[46] Additionally, as mentioned previously, the modeled cooling tower stack parameters differ from what was provided by CFI in the Emission Inventory Questionnaire for the cooling tower.[47]

Furthermore, as noted by Dr. Pless, CFI relied on a 2004 paper by Reisman and Frisbie to calculate PM10 and PM2.5 emission factors for the cooling tower.[48] However, EPA has questioned the assumptions made by Reisman and Frisbie, and actual data suggests that the cooling water tower PM2.5 fraction is very close to the total PM10 fraction, meaning PM2.5 emissions would be much higher.[49] Assuming PM10 consists entirely of PM2.5, the PM2.5 emissions from the cooling tower increase from 0.01 tpy to 4.42 tpy.[50] This increases the Facility's PM2.5 PSD emissions to 14.3 tpy, which exceeds the PM2.5 PSD *de minimis* threshold

[40] Id. at 31–33.
[41] *Id.* at 34–38.
[42] *Id.* at 15.
[43] *Id.*
[44] Draft Permit Package at PDF pg. 350.
[45] LAC 33.III.5112, Table 51.1.
[46] *Id.* at 42.
[47] *Id.*
[48] *Id.* at 45–46.
[49] *Id.*
[50] *Id.*

of 10 tpy.[51] As such, CFI should conduct air dispersion modeling and a BACT analysis for PM2.5.

6. CFI does not consider all maintenance/startup/shutdown emissions.

As stated in Dr. Pless's report, CFI does not appear to consider all maintenance/startup/shutdown ("MSS") emissions.[52] For example, the nearby proposed Air Products facility calculates MSS emissions for natural gas and feed pretreatment, natural gas venting prior to introduction to gasifier, shutdown flaring, and gasifier trip.[53] As such, LDEQ should require CFI to revise their application to include all MSS emissions.

7. CFI should have included emissions from marine vessel auxiliary boilers in their PTE calculations.

CFI should have included emissions from marine vessel auxiliary boilers or other non-internal combustion engine emission units that generate steam or electricity for marine vessel loading operations. CFI estimates fugitive ammonia emissions from ship loading operations (assuming 40 ships per year)[54]; however, CFI did not consider any other emissions from the marine vessel during loading operations.

EPA has stated that, while "to and fro" emissions from marine vessels are properly treated as non-stationary source emissions,

> We . . . intend to consider . . . the emissions from activities in support of the port's function – i.e., those related to processing and transferring gas at the port, regardless of whether they occur on the metering platform or on marine vessels propelled by external combustion engines, as stationary emissions of the port for [Clean Air Act] Title I and Title V purposes. The nature of controls, if any, EPA will propose to impose on those emissions will be reflected in a draft preconstruction/Title V permit.[55]

In a 2023 letter regarding a proposed permit for Bluewater Texas Terminals, LLC, EPA stated that:

> Accordingly, and following from the discussion above, EPA views the *NRDC* holding to support the conclusion that, when the [Offshore Supply Vessel] is holding a stationary position and transferring and treating emissions from marine loading operations, the

[51] *Id.*
[52] *Id.* at 49.
[53] *Id.*
[54] Draft permit package at PDF pg. 281.
[55] EPA New Source Review Workshop Manual Draft Oct. 1990 ("NSR Manual") at A.18, https://www.epa.gov/nsr/nsr-workshop-manual-draft-october-1990 ("As a result of a court decision in NRDC v. EPA, 725 F.2d 761 (D.C. Circuit 1984), emissions from vessels at berth ("dockside") [sic] not to be included in the determination of secondary emissions but are considered primary emissions for applicability purposes.") (Excerpt at Attachment X)

> emissions from the marine turbines onboard should be included in the [potential to emit] of the [Deepwater Port] for NSR permitting purposes.[56]

The principle that dockside emissions are stationary source emissions is recognized by, among others, the Texas Commission on Environmental Quality ("TCEQ"). TCEQ's air permit writer guidance states:

> Certain emissions from ships and barges located at berth are considered to be primary emissions and must be included in the PTE determination. These emissions include loading emissions, any vessel equipment meant to support the transfer of materials between the vessel and shore, and the emissions from the ship's boilers used to support the transfer of materials between the vessel and shore facilities while the ship is docked.[57]

Further, TCEQ's air permit regulations require information demonstrating that emissions from the facility, "including any associated dockside vessel emissions," meet air quality requirements.[58]

As such, CFI should have considered emissions from on-ship units providing power during loading operations or explicitly stated that shore power would be used to power loading operations. If shore power is used, it should be an explicit permit requirement.

C. CFI's NOx BACT analysis for fired sources is deficient.

As mentioned in Dr. Pless's report, the Project would operate a 433.9-MMBtu/hr Steam Superheater (EQT 0005), a 355.01-MMBtu/hr Fired Process Heater (EQT0028), and a 566.25-MMBtu/hr Auxiliary Boiler (EQT 0011).[59] CFI's BACT analyses for these sources determines the use of selective catalytic reduction ("SCR") and low NOx burners with a proposed BACT limit of 9 parts per million by volume, dry ("ppmvd") adjusted to 3% oxygen ("O_2") (30-day rolling average) as NOx BACT.[60] However, Dr. Pless notes that lower concentrations are feasible, achieved in practice, and have been determined as BACT by other permitting agencies.[61] For example, 7.4 ppmvd NOx corrected to 3% O_2 is feasible, achieved in practice, and determined as BACT by EPA.[62] The lowest major source BACT for such sources is 5 ppmvd NOx corrected to 3% O_2 determined by Sacramento Air Quality Management District

---

[56] Enclosure (BWTX Proposed DWP Project Clean Air Act (CAA) Permit Application Review) to Letter from David Garcia, Director, Air and Radiation Division, EPA Region 6, to Mr. B.R. Sutaria, Vice President Bluewater Texas Terminals, LLC, April 18, 2023, at 5 of 13 https://downloads.regulations.gov/EPA-R06-OAR-2020-0510-0375/content.pdf.

[57] Air Permit Reviewer Reference Guide, APDG 5881, Major New Source Review - Applicability Determination, Air Permits Division Texas Commission on Environmental Quality, January 2022 at 8, https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/fnsr_app_determ.pdf.

[58] 30 TAC 116.111(a)(2).

[59] Pless Report at 50–51.

[60] *Id.* at 51.

[61] *Id.*

[62] *Id.*

("SCAQMD") in 2016 (achieved with a combination of low NOx burner, flue gas recirculation, and oxygen controller).[63]

D. CFI's ozone impacts analysis is deficient and does not demonstrate compliance with the 8-hour ozone NAAQS.

1. Ambient ozone concentrations are already concerningly close to the 8-hour ozone NAAQS.

CFI did not analyze ambient ozone concentration data from nearby air quality monitors. The reason CFI gives for not doing so—which we believe is not appropriate in this case—is the project's estimated ozone impact is slightly below EPA's recommended SIL for ozone of 1.0 part per billion (ppb). There are several issues related to the CFI's calculation of the project's ozone impacts and use of the SIL, which are discussed in later sections, but had CFI considered ambient ozone concentrations measured by nearby air quality monitors, they would have found the ambient concentrations are concerningly close (or even exceed) the 8-hour ozone NAAQS (0.070 parts per million (ppm), which is equivalent to 70 ppb).

The form of the ozone "design value" (i.e., the metric calculated from ambient ozone data that is then compared to the NAAQS) is "the 3-year average of the annual fourth-highest daily maximum 8-hour average" ozone concentration.[64] The most recent (2022–2024) design values for monitors near the proposed Facility are shown in Table 2.

Table 2 Design values for ozone monitors near the proposed Facility. Design values are from EPA's 2024 ozone design value report.[65] (Note: Design values are reported by EPA in ppm—they have been converted to ppb to make them easier to read.)

Monitor AQS ID	Monitor Name	Approximate Distance from CF Industries Blue Point (mi)	2022-2024 Design Value (ppb)
22-005-0004	Dutchtown	5.3	68
22-047-0012	Carville	6.0	74
22-093-0002	Convent	12.9	65
22-063-0002	French Settlement	16.2	68
22-047-0009	Bayou Plaquemines	17.3	70

[63] *Id*.
[64] 40 CFR 50.19(b).
[65] EPA 2024 Ozone Design Value Report available at https://www.epa.gov/air-trends/air-quality-design-values#report.

As can be seen, the closest monitor (Dutchtown) is within 2 ppb of the ozone NAAQS. The next closest monitor (Carville), which is only 0.7 miles further, shows an exceedance of the ozone NAAQS, and monitors further away generally show the broader area has ambient ozone concentrations concerningly close to the NAAQS. As such, any source of ozone precursor emissions (i.e., NOx and VOC emissions) could potentially cause or contribute to an exceedance of the NAAQS.

2. CFI does not include sufficient justification for their assumptions used in their ozone impacts analysis.

CFI used EPA's Modeled Emission Rates for Precursors (MERPs) methodology, a Tier 1 demonstration tool for ozone under the PSD permitting program, to assess the project's ozone impacts.[66] The MERPs methodology was developed by EPA using sophisticated photochemical grid modeling to estimate the ozone impacts of hypothetical sources with varying characteristics (e.g., precursor emission rates, stack heights) at select locations throughout the U.S. The end result is essentially a database of the maximum downwind ozone impact for a given precursor emission rate and stack height at a given location that can be used to approximate a facility's ozone impact without having to use a complex photochemical grid model.

A critical step for using the MERPs methodology is selecting the appropriate location from which to pull MERP values because the MERP location implicitly represents the chemical and physical environment that governs the relationship between precursor emissions and ozone impacts. In EPA's updated guidance document on using MERPs, EPA specifically states:

> The permit applicant should provide the appropriate permitting authority with a technically credible justification that the source characteristics (e.g., stack height, emissions rate) of the specific project source described in a permit application and the chemical and physical environment (e.g., meteorology, background pollutant concentrations, and regional/local emissions) near that project source are adequately represented by the selected hypothetical source(s).[67]

However, the only justification CFI provided for their selection of the MERP location used is:

> The first step is to define the applicable MERP to use. EPA assessed three sources in Louisiana: Acadia, Lincoln, and Orleans. The Orleans source is the closest to and most representative of the Blue Ammonia Plant.[68]

Furthermore, this justification only appears in CFI's March 5, 2024, initial modeling protocol—no justification appears in the modeling protocol included in CFI's February 7, 2025, revised application or April 3, 2025, modeling report.

---

[66] The MERPs methodology can also be used to estimate secondary PM2.5 impacts.
[67] EPA, Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program with 2024 Clarification Memo ("EPA MERPs Guidance Document") at PDF pg. 6. Available at: https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf
[68] March 5, 2024, Modeling Protocol at PDF pg. 36.

Beyond being insufficient, the justification given in the initial modeling protocol naïvely assumes that closest automatically means most representative. Although the Orleans Parish MERP location (30.091878° N, 89.878967° W; 111 km (69 mi) away) is closer to the proposed Facility than the Acadia Parish MERP location (30.240934° N, 92.616466° W; 153 km (95 mi) away), it is not significantly closer, and as such, other characteristics should be used to determine representativeness. In the MERPs guidance document, EPA states:

> Additional information has been provided for each source to facilitate qualitative comparison between hypothetical sources with project sources. The additional information includes the terrain within 50 km of the source and maximum grid cell percent urban landcover within 50 km of the source to provide some additional information about nearby orography and whether the source is in proximity to population centers.[69]

Both the Orleans and Acadia MERP locations have similar terrain; however, they differ significantly in the amount of urban landcover. The "maximum nearby urban (%)" value, which "provides the highest percent urban landcover in any grid cell near (within 50 km) the source,"[70] is significantly higher for the Orleans MERP location—50.4% versus 6.5% for the Acadia MERP location. In other words, the Orleans MERP location represents an urban chemical environment, while the Acadia MERP location represents a rural chemical environment. This difference has implications for ozone impacts because as EPA states in the MERPs guidance document, rural areas tend to be NOx limited, meaning more ozone is formed per ton of NOx in these areas.[71] This difference in chemical environment is demonstrated by the difference in MERP values—a source emitting 500 tpy of NOx from a 90 m stack in Orleans Parish would have a maximum ozone impact of 1.3 ppb, while the same source in Acadia Parish would have a maximum ozone impact of 2.5 ppb (i.e., nearly twice the impact).

Aerial imagery shows that the area around the proposed project site is mostly rural with patchy industrial development. Additionally, an analysis of 2022v2 Emissions Modeling Platform county-level data, which includes point sources, nonpoint sources (including biogenic sources), onroad sources, and offroad sources, shows that Ascension Parish's NOx-to-VOC reported emissions ratio (0.618 ton NOx per 1 ton VOC) is closer to Acadia Parish's ratio (0.360 ton NOx per 1 ton VOC) than Orleans Parish's ratio (0.977 ton NOx per 1 ton VOC).[72] As such, the use of the more rural Acadia MERP values is likely more appropriate, and even if neither the Orleans nor the Acadia MERP values perfectly represent conditions at the project site, CFI and LDEQ should err on the side of conservatism given ambient ozone concentrations are very close

---

[69] EPA MERPs Guidance Document at PDF pg. 36.
[70] EPA MERPs Guidance Document at PDF pg. 79.
[71] EPA MERPs Guidance Document at PDF pg. 27.
[72] 2022v2 Emissions Modeling Platform county-level data available at https://www.epa.gov/air-emissions-modeling/2022v2-emissions-modeling-platform. The largest source of VOCs in Acadia and Ascension Parishes are biogenic sources (e.g., plants), which makes sense given how rural the two parishes are. The largest source of VOCs in Orleans Parish are solvents (followed by biogenic sources). Biogenic VOC totals by parish are as follows: Acadia Parish: 12,069 tpy biogenic VOCs (83% of total VOCs), Ascension Parish: 10,554 tpy biogenic VOCs (62% of total VOCs), Orleans Parish: 2,250 tpy biogenic VOCs (27% of total VOCs).

to the NAAQS.[73] Use of Acadia MERP values, as shown in the attached expert report by Dr. William Battye, results in the proposed Facility's ozone impact being 1.5 ppb, exceeding the 1.0 ppb SIL for ozone.[74] (Given how close ambient ozone concentrations are to the NAAQS, we do not believe it is appropriate to use the SIL to determine whether a source causes or contributes to an exceedance of the NAAQS (i.e., our position is that a source with impacts below the SIL could still contribute to an exceedance) but that is discussed in a later section of our comment.)

With the SIL exceeded, the next step, which CFI did not do, is to conduct a cumulative impact analysis. EPA states in the MERPs guidance document:

> As detailed in Section 9 of the *Guideline*, for situations where the project source is not able to demonstrate compliance through the source impact analysis, a cumulative impact analysis can be conducted that accounts for the impacts from the project source, impacts from nearby sources (as appropriate), and monitored background levels. The cumulative impacts are then compared to the NAAQS to determine whether the project source could cause or contribute to a NAAQS exceedance.[75]

As shown in Dr. Battye's report, impacts from nearby sources that have been permitted but not yet built (and so are not reflected in the monitored background level) are estimated to be 2.2 ppb, resulting in a total modeled impact of 3.7 ppb.[76] When this is added to the most recent (2022–2024) design value from the closet ozone monitor in Dutchtown (68 ppb),[77] this results in an exceedance of the 8-hour ozone NAAQS (71.7 ppb vs. 70 ppb).[78] In the MERPs guidance document, EPA states:

> …[I]f equation 3 [equation for cumulative impact analysis] results in an air quality level greater than the NAAQS, then the permit applicant should consult with the reviewing authority to determine the next step in the demonstrating project source impact at the location of the NAAQS violation. This may necessitate more refined modeling to reconcile project source impacts and monitored design values to complete the second phase of the cumulative impact analysis.

As such, the MERPs methodology fails to demonstrate the proposed Facility would not cause or contribute to an exceedance of the 8-hour ozone NAAQS, and as such, LDEQ should not grant CFI a PSD permit until CFI conducts more sophisticated modeling (e.g., using a photochemical grid model) to demonstrate otherwise.

---

[73] This would also be consistent with the general theme of erring on the side of conservatism found throughout EPA's MERPs guidance document.
[74] Battye Ozone Report at 4.
[75] EPA MERPs Guidance Document at PDF pg. 69.
[76] Battye Ozone Report at 5–6.
[77] Dutchtown monitoring site AQS ID: 22-005-0004. Ozone design value from EPA's 2024 Ozone Design Values Report available at https://www.epa.gov/air-trends/air-quality-design-values#report.
[78] Battye Ozone Report at 5.

3. CFI incorrectly calculated the proposed Facility's ozone impact.

Notwithstanding that CFI should have used MERP values from Acadia Parish instead of from Orleans Parish, CFI incorrectly calculated the proposed Facility's ozone impact.[79] In Table 13 in the modeling report, CFI states they were using the NOx MERP value for a 500 tpy source with a 90 m stack in Orleans Parish.[80] However, the values given in the "MERP (tpy)" and "Max Concentration (ppb)" columns are actually for a 500 tpy source with a 10 m stack and reflect a lower amount of ozone formation per ton of NOx.[81] Had CFI used the proper values for a 500 tpy source with a 90 m stack in Orleans Parish, the values given in the "MERP (tpy)" and "Max Concentration (ppb)" columns would be 375 tpy and 1.33 ppb, respectively. Furthermore, the proposed facility-wide NOx emission rate used by CFI (289.65 tpy) is lower than the facility-wide NOx emission rate included in the draft permit package (296.67 tpy). As such, the proposed Facility's impact would be calculated as follows:

$$296.67\ tpy\ NO_x \times \frac{1.33\ ppb\ O_3}{500\ tpy\ NO_x} + 37.30\ tpy\ VOC \times \frac{0.20\ ppb\ O_3}{500\ tpy\ VOC} = 0.80\ ppb\ O_3$$

Had CFI used the correct NOx MERP value and used the facility-wide permitted emission rate for NOx, the proposed Facility's estimated ozone impact would be 0.8 ppb.

Furthermore, as discussed earlier, we contend that CFI vastly underestimated the Facility's potential VOC emissions by inappropriately reducing estimated VOC emissions from the CO2 vent. Had CFI appropriately estimated VOC emissions from the CO2 vent (351.81 tpy based on the maximum hourly emission rate), the Facility's potential VOC emissions would be 360.51 tpy. The Facility's ozone impact would be calculated as follows:

$$296.67\ tpy\ NO_x \times \frac{1.33\ ppb\ O_3}{500\ tpy\ NO_x} + 360.51\ tpy\ VOC \times \frac{0.20\ ppb\ O_3}{500\ tpy\ VOC} = 0.93\ ppb\ O_3$$

Had CFI appropriately estimated VOC emissions from the CO2 vent, the Facility's estimated ozone impact would be 0.93 ppb, which is very close to the ozone SIL of 1.0 ppb.

4. The use of a SIL to demonstrate that the proposed Facility will not cause or contribute to an exceedance of the 8-hour ozone NAAQS is inappropriate because ambient ozone concentrations are already close to the NAAQS.

CFI claims that because the proposed Facility's estimated ozone impact (based on Orleans Parish MERP values) is less than EPA's recommended SIL for ozone (1.0 ppb), the Facility would not cause or contribute to an exceedance of the 8-hour ozone NAAQS. However, given that nearby ozone monitors show ambient ozone concentrations are just under or even exceed the NAAQS, the use of the ozone SIL is inappropriate in this case.

[79] *Id.* at 2.
[80] Modeling Report at 15 (PDF pg. 18).
[81] EPA, MERPs View Qlik, available at https://www.epa.gov/scram/merps-view-qlik.

EPA's 2018 SIL guidance document states that "[u]sing a quantitative threshold for this purpose is permissible as long as the EPA or the appropriate permitting authority provides a reasoned explanation for why impacts below that value do not cause or contribute to a violation in a particular context."[82] However, there is no justification for the use of the ozone SIL in the permit record other than "the proposed project impact is less than the SIL and the [ozone impacts] analysis was complete."[83]

Furthermore, EPA's 2018 SIL guidance also states:

> However, upon considering the permit record in an individual case, if a permitting authority has a basis for concern that a demonstration that a proposed source's impact is below the relevant SIL value at all locations is not sufficient to demonstrate that the proposed source will not cause or contribute to a violation, then the permitting authority should require additional information from the permit applicant to make the required air quality impact demonstration.[84]

Given that ambient ozone concentrations are just under the NAAQS, LDEQ should have "basis for concern" that being below the ozone SIL is not sufficient to demonstrate that the proposed Facility will not cause or contribute to a violation of the ozone NAAQS. As such, LDEQ should require CFI to provide additional information (i.e., conduct a cumulative impact analysis) to make an appropriate determination.

E. CF's ammonia modeling is deficient and does not demonstrate compliance with Louisiana's ambient air standard for ammonia.

1. Ammonia fugitive emission rates are underestimated.

As stated by Dr. Battye in his ammonia modeling report, ammonia fugitive emission rates are likely underestimated.[85] (This is consistent with Dr. Pless' conclusion.[86]) CFI used a short-term adjustment factor of 1.26 for fugitive emissions, while it is common EPA practice to use a factor of 2.[87] Furthermore, as mentioned elsewhere in this comment letter, CFI used average SOCMI emission factors multiplied by a "molecular weight factor" of 0.243 to estimate fugitive ammonia emissions. The use of this "molecular weight factor" is not mentioned anywhere in EPA's guidance document.[88] Had CFI not used this adjustment factor, fugitive ammonia emissions would be 4.1 times higher, resulting in a maximum 8-hour modeled ammonia

---

[82] EPA, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program, April 17, 2018 ("2018 EPA SIL Guidance"), at 8 (PDF pg. 9). Available at https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf.
[83] Modeling Report at 15 (PDF pg. 18).
[84] 2018 EPA SIL Guidance at 18 (PDF pg. 19)
[85] Battye Ammonia Report at 2–5.
[86] Pless Report at 26–39.
[87] Battye Ammonia Report at 3–4.
[88] *Id.* at 3.

concentration of 677 µg/m^3, which exceeds Louisiana's ambient air standard for ammonia (640 µg/m^3).[89] According to LAC 33:III.5109.B.3, "[n]ew major sources shall demonstrate compliance with an ambient air standard in an application for a permit in accordance with LAC 33:III.5111." Had CFI properly estimated fugitive ammonia emissions, the project's modeled ammonia impacts would exceed Louisiana's ambient air standard for ammonia. As such, according to LAC 33:III.5109.B.3, LDEQ must require CFI to make necessary design changes and redo their ammonia modeling to demonstrate compliance with the ammonia ambient air standard.

2. Ammonia modeling shows exceedance of Louisiana's ambient air standard for ammonia.

As mentioned in Dr. Battye's report, when ammonia emissions from other nearby facilities are considered, modeled ammonia concentrations exceed Louisiana's ambient air standard for ammonia by a significant margin.[90] These modeling results show that the area around the proposed project site is already subject to significant ammonia impacts, and the proposed Facility would only exacerbate them. As stated previously, LDEQ must require CFI to make necessary design changes to ensure that the Facility does not cause or contribute to an exceedance of Louisiana's ambient air standard for ammonia.

3. There are no ammonia monitors nearby to determine current impacts of ammonia emissions from nearby existing facilities.

While air dispersion modeling is a useful tool to estimate ammonia impacts, monitors are necessary to collect real-world data to verify impacts. LDEQ does not currently operate any stationary monitors to determine whether ambient ammonia concentrations comply with the state standard or exceed health-based guidelines.[91] Comparisons of ammonia concentrations against health-based guidelines are necessary to achieve LDEQ's mission of protecting public health and well-being. Without actually measuring ammonia concentrations in an area of significant ammonia emissions, LDEQ is essentially flying blind.

Furthermore, Louisiana's ammonia standard is outdated and fails to protect public health. As other commenters have previously noted, over 400 peer-reviewed studies on the respiratory impacts of ammonia exposure have been published since LDEQ's ammonia standard was established in 1991.[92] Yet, LDEQ has failed to update this standard, effectively ignoring a vast body of scientific understanding. Furthermore, it's unclear if LDEQ is even meeting its legal obligation under LAC 33:III.5109.B.6, which states "[t]he administrative authority shall periodically, at least every 36 months, review and update the ambient air standards listed for each toxic air pollutant in LAC 33:III.5112, Table 51.2." Consequently, LDEQ's ammonia standard is

[89] *Id.* at 4.
[90] *Id.* at 5–9.
[91] Nov 26, 2025, email from LDEQ in response to Public Record Request 0107393.
[92] Dec 18, 2024, comments submitted to LDEQ by Tulane Environmental Law Clinic on behalf of Refined Community Empowerment on the Application for Minor Source Air Permit for St. Charles Clean Fuels, LLC – Blue Ammonia Facility, St. Rose, St. Charles Parish, Louisiana Agency Interest No. 236110, Permit Number 2520-00187-00, Activity Number PER 202300001.

high compared to other states that consider the best available science. For example, the Massachusetts ambient air standard for ammonia, which was updated in 2011, establishes an acute (24-hr average) exposure limit of 100 µg/m3.[93] Unlike LDEQ, the Massachusetts Department of Environmental Protection provides current and detailed methodology for the derivation of its ambient air standards, including the date of the last revision.[94] As previously noted, the Louisiana ammonia AAS lacks any scientific basis, rendering it completely arbitrary.[95]

F. CFI's air dispersion modeling has several deficiencies and does not demonstrate compliance with the NAAQS.

1. CFI inappropriately excludes NOx emissions from standby generators and firewater diesel pumps in the 1-hour NO2 NAAQs analysis.

CFI inappropriately excludes NOx emissions from standby generators 1–5 and firewater pumps 1–2 in the 1-hour NO2 NAAQS analysis. CFI vaguely references "EPA guidance suggested in the memorandum *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard*" to justify excluding sources that would operate 100 hours per year (under non-emergency conditions) from the 1-hour NO2 NAAQS analysis without providing a more specific reference to the "EPA guidance suggested."[96]

The exclusion of these sources is inappropriate because the form of the 1-hour NAAQS is "the three-year average of the annual 98th percentile of the daily maximum 1-hour average concentration,"[97] and as such, even intermittent sources could reasonably be expected to contribute to the exceedance of the NAAQS. Furthermore, as shown in Table 3, the maximum hourly NOx emission rate from these excluded sources are non-negligible. By excluding these sources, the project's estimated maximum 1-hour NO2 impact is 7.23 µg/m^3, which is just shy of the 1-hour NO2 SIL of 7.5 µg/m^3, meaning CFI did not do a cumulative impact analysis. Had CFI appropriately included the standby generators and firewater pumps in the 1-hour NO2 NAAQS analysis, the project's 1-hour NO2 impacts would have likely exceeded the SIL, meaning CFI would have had to do a cumulative impact analysis. As such, LDEQ should require CFI to redo the 1-hour NO2 NAAQS analysis including all NOx sources.

---

[93] MassDEP Ambient Air Toxic Guidelines, available at https://www.mass.gov/info-details/massdep-ambient-air-toxics-guidelines.

[94] *Id.* The EPA's Toxicological Review of Ammonia, published in September 2016, establishes a recommended maximum concentration of 500 µg/m3, citing scientific studies published in 1998, 2001, and 2007—for an acute duration of 25 hours or less. Toxicological Review of Ammonia Noncancer Inhalation: Executive Summary, EPA (September 2016), available at: https://ordspub.epa.gov/ords/eims/eimscomm.getfile?p_download_id=529124; see EPA, IRIS Glossary, available at: https://www.epa.gov/iris/iris-glossary#:~:text=Acute%20Reference%20Concentration%20(RfC)%3A,of%20deleterious%20effects%20during%20a/.

[95] Dec 18, 2024, comments to LDEQ submitted by Tulane Environmental Law Clinic.

[96] Modeling Report at 4 (PDF pg. 7).

[97] 40 CFR 50.11(f).

Table 3 Maximum hourly NOx emission rate for intermittent sources excluded from 1-hour NO2 NAAQS analysis.

Source ID	Source Description	Max Hourly NOx Emission Rate (lb/hr)	Draft Permit Package PDF Pg.
GEN1	Standby Generator 1	8.20	26
GEN2	Standby Generator 2	8.20	26
GEN3	Standby Generator 3	54.80	26
GEN4	Standby Generator 4	54.80	26
GEN5	Standby Generator 5	54.80	26
FW1	Firewater Diesel Pump 1	19.20	26
FW2	Firewater Diesel Pump 2	19.20	26

2. CFI does not justify the very high stack velocities for the standby generators.

As shown in Table 4, the modeled stack velocities for the five standby generators are very high. This results in greater modeled dispersion and hence lower modeled air quality impacts. However, CFI provides no justification for these very stack velocities. As such, LDEQ should require CFI to provide justification, and if CFI cannot provide justification, LDEQ should require CFI to redo air dispersion modeling with more appropriate (i.e., lower) modeled stack velocities.

Table 4 Modeled stack velocities for standby generators.

Source ID	Source Description	Stack Velocity (ft/sec)	Modeling Report Page
GEN1	Standby Generator 1	775.96	8 (PDF pg. 11)
GEN2	Standby Generator 2	795.40	8 (PDF pg. 11)
GEN3	Standby Generator 3	585.40	8 (PDF pg. 11)
GEN4	Standby Generator 4	602.50	8 (PDF pg. 11)
GEN5	Standby Generator 5	602.50	8 (PDF pg. 11)

G. The application materials and draft permit package have significant deficiencies.

1. The revised application is incomplete.

LDEQ may not issue the permit because the application is incomplete. Louisiana's SIP requires an applicant to provide information about a project's proposed processes and products,

among other things. *See generally* LAC 33:III.517. Unless an application is "administratively complete," LDEQ may not issue a permit. LAC 33:III.519.A; *see also Louisiana Env't Action Network, Inc. v. Brown*, 2019-0607 (La. App. 1 Cir. 1/9/20), 294 So. 3d 1066, 1071, *writ denied,* 2020-00246 (La. 4/27/20), 295 So. 3d 950 (vacating a permit issued by LDEQ because it "did not contain required information" and LDEQ "improperly accepted the application as administratively complete and issued a public notice giving public access to an incomplete application.").

As mentioned in Dr. Pless's report, CFI's February 7, 2025, revised application, which was submitted after CFI switched the ammonia production technology from steam methane reforming to autothermal reforming, fails to include an updated block flow diagram as required by LDEQ's guidance for preparing applications.[98] The revised application also does not include an updated plot plan.[99] Additionally, CFI provides no information on the ammonia storage tanks (e.g., capacity, construction type, turnover, location, etc.), and ammonia storage tanks are not listed in the draft permit.[100] Furthermore, there are several issues with CFI's Emission Inventory Questionnaires (EIQs).

The EIQs for several units are missing necessary parameters as shown in Table 5 below.

Table 5 Emission units missing parameters in their respective EIQs in the revised application.

Emission Point ID No.	Emission Source Name	Missing Parameter(s)	Draft Permit Package PDF Pg.
22B001 (SU)	Steam Superheater Startup	Stack Gas Exit Velocity, Stack Gas Flow at Process Conditions	198
13B001 (SU)	Fired Process Heater Startup	Stack Gas Exit Velocity, Stack Gas Flow at Process Conditions	223
23U510 (SU)	Auxiliary Boiler Startup	Stack Gas Exit Velocity, Stack Gas Flow at Process Conditions	207
SL1	Ammonia Ship Loading Emissions	Height of Stack Above Grade*	211
WWT	Wastewater Treatment System	Height of Stack Above Grade*	203
FUG1	Ammonia Plant Fugitives	Height of Stack Above Grade*	227

*Fugitive sources require release height

Additionally, some units have mismatches between parameters included in their EIQs (including revised EIQs) and what was modeled (Table 6). Although some of these mismatches (e.g., lower

[98] Pless Report at 6.
[99] *Id.*
[100] *Id.* at 7.

modeled stack gas exit velocity) result in higher modeled impacts, some of these mismatches (e.g., higher modeled stack height) result in lower modeled impacts. The net effect of these discrepancies on the modeling results is unclear, and LDEQ should require CFI to address these differences between what was included in the EIQs and what was modeled. This is particularly relevant for the 1-hour NO2 NAAQS modeling performed where the model results were within 0.27 µg/m^3 (3.6%) of the corresponding SIL (7.23 µg/m^3 vs. 7.5 µg/m^3).

Table 6 Emission units with mismatch between release parameters in EIQs and what was modeled.

Emission Point ID No.	Emission Source Name	Parameter Name	EIQ Value	Modeled Value	Units	Notes
13U501	Combined Heater Stack	Stack Gas Exit Velocity	36.72	34.01	ft/sec	
23U510	Auxiliary Boiler	Stack Gas Exit Velocity	54.96	30.44	ft/sec	
33CT001	Cooling Tower	Stack Height	47.25	63	ft	
33CT001	Cooling Tower	Stack Gas Exit Velocity	0.0033	24	ft/sec	
33CT001	Cooling Tower	Diameter	3.248	20	ft	
35V001	Syngas Flare	Diameter	40.62	45.44	ft	Short-term modeled value
35V001	Syngas Flare	Diameter	40.62	12.28	ft	Long-term modeled value
35V002	Ammonia Flare	Diameter	17.91	2.84	ft	Short-term modeled value
35V002	Ammonia Flare	Diameter	17.91	2.54	ft	Long-term modeled value
VNT-CO2	CO2 Vent	Stack Height	195	170	ft	
VNT-CO2	CO2 Vent	Stack Temperature	99	108	°F	
VNT-CO2	CO2 Vent	Stack Gas Exit Velocity	95	120.05	ft/sec	
50V001	Ammonia Storage Tank Flare A	Diameter	4.73	1.53	ft	Short-term modeled value

50V001	Ammonia Storage Tank Flare A	Diameter	4.73	1.37	ft	Long-term modeled value
50V001	Ammonia Storage Tank Flare B	Diameter	4.73	1.53	ft	Short-term modeled value
50V001	Ammonia Storage Tank Flare B	Diameter	4.73	1.37	ft	Long-term modeled value
18B001	Ammonia Synthesis Loop Startup Heater	Stack Height	120	75	ft	
GEN1	Standby Generator 1	Stack Gas Exit Velocity	969.13	775.96	ft/sec	
GEN2	Standby Generator 2	Stack Gas Exit Velocity	993.42	795.40	ft/sec	
GEN3	Standby Generator 3	Stack Gas Exit Velocity	0.00	585.40	ft/sec	
GEN4	Standby Generator 4	Stack Gas Exit Velocity	0.00	602.50	ft/sec	
GEN5	Standby Generator 5	Stack Gas Exit Velocity	0.00	602.50	ft/sec	

In addition, although CFI relies on the use of CCS to escape compliance with Clean Air Act requirements for major sources of VOCs, the application provides no specific information about the pipeline and CCS facility. For all these reasons, the application is incomplete and LDEQ may not issue the permit.

2. <u>The draft permit package has significant deficiencies.</u>

As Dr. Pless notes in her report, the draft permit package is poorly organized, not searchable, and failed to include the air dispersion modeling report.[101] Additionally, some emission units are missing stack (release) parameters in the emission unit inventory included in the draft permit package (Table 7).

Table 7 Emission units missing parameters in draft permit package inventory.

Emission Point ID No.	Emission Source Name	Missing Parameter(s)	Draft Permit Package PDF Pg.
33CT001	Cooling Tower	Velocity, Flow Rate	22

[101] *Id.*

GEN3	Standby Generator 3	Velocity, Flow Rate	22
GEN4	Standby Generator 4	Velocity, Flow Rate	22
GEN5	Standby Generator 5	Velocity, Flow Rate	23
50E007	Evaporative Condenser A	Velocity, Flow Rate, Temperature	23
50E011	Evaporative Condenser B	Velocity, Flow Rate, Temperature	23

II. The Draft Title V Permit Is Severely Deficient and Does Not Comply with the Requirements of the Clean Air Act.

A. LDEQ must revise the draft Title V permit to make clear what requirements apply to each unit.

Each Title V permit "shall include enforceable emissions limitations and standards"" and "such other conditions as are necessary to assure compliance with the applicable requirements." 42 U.S.C. 7661c(a). Further, each permit must "set forth inspection, entry, monitoring, compliance certification, and reporting requirements to assure compliance with the permit terms and conditions." 42 U.S.C. 7661c(c). One of the primary purposes of Title V is "to facilitate compliance and enforcement" of the Act by consolidating all federal air pollution limits and other requirements (including those established in a SIP) for a facility into a single, federally enforceable permit. *Util. Air Regulatory Grp. v. EPA*, 573 U.S. 302, 309 (2014). EPA has repeatedly emphasized that this requires permitting authorities to ensure both that all limits applicable to the permittee are clear on the face of the permit, and that these limits are supported by monitoring, recordkeeping, and reporting requirements "sufficient to enable regulators and citizens to determine whether the limit has been exceeded and, if so, to take appropriate enforcement action."[102]

The draft Title V permit is severely deficient and fails to meet these basic requirements of the Clean Air Act in at least three significant ways.

1. The draft Title V permit improperly incorporates requirements from CFI's PSD Permit No. PSD-LA-859. It also improperly incorporates requirements from federal regulations through vague and unclear references—in some cases simply citing the entire subchapter—making it impossible to decipher what specific requirements apply to the units in question.

2. LDEQ states that it has set forth permitted emission limits for emission units in two tables: "Emission Rates for Criteria Pollutants" and "Emission Rates for TAP/HAP &

[102] *In the Matter of Orange Recycling and Ethanol Production Facility, Pencor-Masada Oxynol, LLC*, EPA Order on Petition No. II-2001-05 (Apr. 8, 2002), at 7. Available at: https://www.epa.gov/sites/default/files/2015-08/documents/masada-2_decision2001.pdf

Other Pollutants." Draft Permit Package at 25-29, 30-32. However, in many cases these tables provide both an "average" and a "maximum" hourly emission rate, with no explanation of which (if any) is actually an enforceable emission limit, and under what circumstances it applies.

3. The Draft Permit does not include monitoring, recordkeeping, or reporting requirements sufficient to assure compliance with numerous limits in the permit—including nearly all of the emission rates listed in the "Emission Rates" tables. In many cases, the permit fails to include *any* monitoring or testing requirements to demonstrate compliance with these limits.

    1. <u>The Draft Title V Permit improperly incorporates the requirements of the PSD Permit and several federal regulations by reference.</u>

Incorporation of requirements into a Title V permit by reference is only appropriate under *very* limited circumstances, and in all cases, "the citations and references must be clear and unambiguous and be enforceable from a practical standpoint." *White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program*. (Mar. 5, 1996) ("White Paper 2") at 5.[103] Incorporation by reference is the exception, not the rule, and "EPA's longstanding guidance on this topic has 'limited' the types of requirements that *can* be incorporated by reference, not those that *cannot* be incorporated by reference." *In the Matter of ExxonMobil Corp., Baytown Chemical Plant,* Order on Petition No. VI-2020-9 (Mar. 18, 2022) ("Exxon Order") at 11.[104] Further, EPA has repeatedly emphasized that 42 U.S.C. 7661c(a) requires, at a minimum, "that all emission limitations and standards **must be included on the face of a title V permit**." *Id.* at 10 (emphasis added). Once all applicable emission limits are placed in the Title V permit and attached to the emissions unit to which they apply, "other provisions, including provisions necessary to assure compliance with those requirements, may be incorporated by reference (provided certain criteria are met)." *Id.* at 10 (citing White Paper 2 at 38, 40).

Any citations or incorporations by reference "must be clear and unambiguous and be enforceable from a practical standpoint." White Paper 2 at 5. This means that:

> Citations, cross references, and incorporations by reference must be detailed enough that the manner in which any referenced material applies to a facility is clear and is not reasonably subject to misinterpretation. Where only a portion of the referenced document applies, applications and permits must specify the relevant section of the document. Any information cited, cross referenced, or incorporated by reference must be accompanied by a description or identification of the current activities, requirements, or equipment for which the information is referenced.

White Paper 2 at 37.

---

[103] White Paper 2 is available on EPA's website at: https://www.epa.gov/sites/default/files/2015-08/documents/wtppr-2.pdf

[104] The Exxon Order is available on EPA's website at: https://www.epa.gov/system/files/documents/2022-04/exxonmobil-baytown-order_3-18-22.pdf

EPA has further clarified that where a cited applicable requirement "provides for different and independent compliance options (e.g., boilers subject to an NSPS [that allows for different compliance methods])," the permitting authority should ensure the permit contains or incorporates by reference "the specific option(s) selected by the source." Exxon Order at 39. It is "not acceptable to use a combination of referencing certain provisions of an applicable requirement while paraphrasing other provisions of that same applicable requirement. Such a practice, particularly if coupled with a permit shield, could create dual requirements and potential confusion." *Id.* at 40.

The Draft Title V Permit violates these requirements by improperly incorporating by reference the requirements of PSD-LA-859, as well as the requirements from federal regulations applicable to several units.

a. *Improper incorporation by reference of the requirements of PSD-LA-859.*

Condition 180 of the Draft Title V Permit improperly incorporates the requirements of CFI's construction permit, PSD-LA-859, by reference. Specifically, Condition 180 simply states that CFI shall "[c]omply with the requirements of PSD-LA-859. This permit includes provisions of the Prevention of Significant Deterioration (PSD) review from Permit PSD-LA-859." EPA has made it very clear that requirements contained in Title I permits are among those requirements that *cannot* be incorporated by reference *at all* and must be explicitly contained within the Title V permit itself. Exxon Order at 11.

From a review of both permits, it appears that the emission limits in the Draft PSD Permit are, in fact, reflected somewhere on the face of the Draft Title V Permit. However, the Draft Title V Permit does not always make it clear that the Draft PSD Permit is the underlying source of those requirements, and this lack of clarity ranges from minor to serious.

In some cases, the Draft Title V Permit conditions reflecting the specific requirements for each unit do state the applicable requirement established by the Draft PSD Permit but simply cite LAC 33:III.509—the provision of Louisiana's SIP generally establishing its PSD permit program—rather than the actual PSD permit. These include Conditions 11, 32-36, 56, 74, 83-84, 102, 135-137, 152-154, 156, and 159-166. LDEQ should revise these conditions to include a specific citation to PSD-LA-859 itself.

A much bigger problem, however, are the numerous emission limits established by the Draft PSD Permit which appear to have been incorporated without indication into the Draft Title V Permit's "Emission Rates for Criteria Pollutants" table. Draft Permit Package at 25-29. These include all of the following emission limits from pages 4-6 of the Draft PSD Permit:

Unit	Pollutant	Limits	
Syngas Flare	NOx	403.94 lb/hr	184.75 tpy
	CO	5,019.37 lb/hr	465.11 tpy
	CO2e	5,007 tpy	
Ammonia Gas Flare	NOx	143.98 lb/hr	28.99 tpy
	CO	0.32 lb/hr	1.10 tpy
	CO2e	369 tpy	
Storage Tank Flares	NOx	47.67 lb/hr	9.51 tpy
	CO	22.30 lb/hr	4.95 tpy
	CO2e	1,055 tpy	
Natural Gas Standby Generators	NOx	8.20 lb/hr	0.41 tpy
	CO	4.20 lb/hr	0.21 tpy
	CO2e	41 tpy	
Diesel Standby Generators	NOx	54.80 lb/hr	2.74 tpy
	CO	4.60 lb/hr	0.23 tpy
	CO2e	141	
Firewater Pumps	NOx	19.20 lb/hr	0.96 tpy
	CO	4.40 lb/hr	0.22 tpy
	CO2e	47	
Combined Heater Stack	NOx	7.05 lb/hr	30.89 tpy
	CO	3.99 lb/hr	17.43 tpy
	CO2e	34,838 tpy	
CO2 Vent	CO	6.12 lb/hr	2.95 tpy
	CO2e	289,272 tpy	

Draft Permit Package at 84-85.

Unlike the conditions mentioned previously which at least cite LAC 33:III.509, the Emissions Rate table is not accompanied by any citations or explanation for the basis for the limits contained in the table—meaning that the only way to determine that some of the limits listed are in fact limits contained in CFI's PSD permit is through a manual review and cross-reference between both permits.[105] EPA's Title V regulations require that each permit "shall specify and reference the origin of and authority for each term or condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based." 40 C.F.R. 70.6(a)(1)(i).

The requirement to clearly specify the origin and underlying authority for each permit term or condition is not a meaningless formality—it is central to the overarching purpose of the

[105] This is just one of the (many) issues with Draft Title V Permit's emission rates tables. As discussed further in Paragraph B of this section, another major issue is that it is unclear whether many of the "emission rates" listed in these tables are even limits at all—an issue compounded by the Emission Rates Tables' lack of citations to any underlying authority.

Title V program, which was "designed to facilitate compliance and enforcement by consolidating into a single document all of a facility's obligations under the [Clean Air] Act." *Util. Air Regulatory Grp. v. EPA*, 573 U.S. 302, 309 (2014). Congress intended for Title V to "substantially strengthen enforcement of the Clean Air Act" by "clarify[ing] and mak[ing] more readily enforceable a source's pollution control requirements." S. Rep. No. 101-228 at 347, 348 (1990), *as reprinted in* A Legislative History of the Clean Air Act Amendments of 1990 (1993), at 8687, 8688. As EPA explained when promulgating its Title V regulations, a permit should "enable the source, States, EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." Operating Permit Program, Final Rule, 57 Fed. Reg. 32,250, 32,251 (July 21, 1992). For each emission limit contained in the "Emission Rates" tables that are requirements of the Draft PSD Permit, LDEQ must revise the Draft Title V Permit to make clear that the origin and underlying source of authority for the emission limit is PSD-LA-859. LDEQ must also revise the Draft Title V Permit to make clear what the origin and underlying source of authority for any other emission limit in the "Emission Rates" tables is (assuming that they are emission limits).

b. *Improper incorporation by reference of requirements in federal regulations.*

For numerous units, the Draft Title V Permit fails to state the applicable emission limit or standard and instead improperly incorporates these requirements through a vague reference to the applicable federal regulation, in some cases simply referencing an entire subchapter, making it impossible to decipher what specific requirements apply to the units in question. These units include:

- The Steam Superheater and Fired Process Heater (EQT 5 & EQT 28, respectively) ("CRG 2 Heaters"), *see* Draft Title V Permit Condition 14;
- The Auxiliary Boiler (EQT 11), *see* Draft Title V Permit Condition 123;
- The Ammonia Synthesis Loop Startup Heater (EQT 29), *see* Draft Title V Permit Condition 140; and
- Standby Generators 3, 4, and 5 (EQTs 19, 20, and 24, respectively) ("Standby Generators"). *See* Draft Title V Permit Condition 85, 86.

i. <u>CRG 2 Heaters (EQT 5, 28)</u>

The Draft Title V Permit improperly incorporates the requirements of 40 CFR 63 Subpart DDDDD, the National Emission Standards for Hazardous Air Pollutants ("NESHAP") for Industrial, Commercial, and Institutional Boilers and Process Heaters, by reference for the CRG 2 Heaters. Specifically, Condition 14 requires that the CRG 2 Heaters:

> Be in compliance with all applicable emission limits, work practice standards, and operating limits in 40 CFR 63 Subpart DDDDD at all times the affected unit is operating except for the periods noted in 40 CFR 63.7500(f). Subpart DDDDD. [40 CFR 63.7500(a)].

Title V permit, Condition 14.

None of the specific conditions applicable to the CRG 2 Heaters expressly state the "emission limits, work practice standards, and operating limits" from Subpart DDDDD that apply to the CRG 2 Heaters. It is also not clear from the provision referenced in Condition 14, or any other conditions in this section which cite to various sections of Subpart DDDDD, what these limits or standards are. The paragraph cited by Condition 14, 40 CFR 63.7500(a), simply states that operators must meet the requirements of this section "that apply to your boiler or process heater," and then itself cites to other sections of Subpart DDDDD which contain tables of the different substantive requirements that apply based on a wide range of unit-specific categorical factors, such as construction date, capacity, type of fuel the unit burns, and other factors related to the design of the unit in question. *See generally* 40 CFR 63.7500(a) (citing at various points to Tables 1 – 14 of Subpart DDDDD). This citation, in other words, merely lists the multiple sections of Subpart DDDDD that *might* apply to these units, and not which ones *actually* apply. This lack of precision is puzzling given that other conditions related to Subpart DDDDD's testing, monitoring, and reporting provisions, have more targeted citations that appear to lay out the precise requirement. For example, Condition 12 expressly states that CFI must conduct a tune-up "every 5 years as specified in 40 CFR 63.7540," and then cites directly to 40 CFR 63.7540(a)(12), which requires a tune-up once every five years for boilers or process heaters meeting specific conditions.[106] This is the way that an incorporation by reference is supposed to work.

In its 2022 Exxon Order, EPA expressly found that incorporating requirements from a federal NESHAP—*especially* from Subpart DDDDD—through a high-level citation to the subpart (like LDEQ has done in Condition 14) is impermissible. EPA noted that since at least 1999, EPA had "rejected suggestions that states have the discretion to include high-level citations to an entire NESHAP subpart," and that permits must "'cite to whatever level is necessary to identify the applicable requirements that apply to each emissions unit or group of emission units (if generic grouping is used), and to identify how those units will comply with the requirements.'" Exxon Order at 16-17 (quoting Letter from John S. Seitz, EPA, to Robert Hodanbosi and Charles Lagges, STAPPA/ALAPCO, at 6 (May 20, 1999)). EPA noted that high-level citations are "especially problematic given the complexity of the subpart DDDDD NESHAP, which contains many different potential requirements that only apply to emission units meeting certain criteria." *Id.* at 18. Thus, "vague, high-level references render it impossible to determine which of these requirements of the subpart DDDDD NESHAP are applicable to specific emission units" and "cannot be said to include or assure compliance with the applicable requirements of the subpart DDDDD NESHAP." *Id*. (citing 42 U.S.C. 7661c(a), (c); 40 C.F.R. 70.6(a)(1), (c)).

LDEQ must revise the permit to (1) include the specific "emission limits, work practice standards, and operating limits" from Subpart DDDDD that apply to each CRG 2 Heater in the text of the permit itself; and (2) revise the permit to reference only the specific parts of Subpart

[106] Though Condition 15, somewhat confusingly, states a requirement to "Conduct an annual, biennial, or 5-year performance tune-up according to 40 CFR 63.7540(a)(10), (a)(11), or (a)(12), respectively, if required to meet an applicable tune-up work practice standard." Commenters assume because Condition 12 specifically cites (a)(12) and a requirement for a 5-year performance tune-up, that (a)(10) and (a)(11) do not apply. However, LDEQ should revise the permit to clarify this and cite only to the provisions of Subpart DDDDD that actually apply.

DDDDD that actually apply to these units, to ensure that the permit "is unambiguous as to which requirements of this subpart (including the emission limitations and standards, as well as the applicable testing, monitoring, recordkeeping, and reporting requirements) are applicable to emission units." Exxon Order at 19.

ii. Auxiliary Boiler (EQT 11)

The text of Condition 123 is identical to that of Condition 14 discussed above, and similarly incorporates the "applicable emission limits, work practice standards, and operating limits in 40 CFR 63 Subpart DDDDD" for the Auxiliary Boiler. For the exact same reasons discussed above, this incorporation by reference is improper, and LDEQ must revise the permit to (1) include the specific "emission limits, work practice standards, and operating limits" from Subpart DDDDD that apply to the Auxiliary Boiler in the text of the permit itself; and (2) revise the permit to reference only the specific parts of Subpart DDDDD that actually apply to this unit.

iii. The Ammonia Synthesis Loop Startup Heater (EQT 29)

The text of Condition 140 is identical to that of Conditions 14 and 123 discussed above, and similarly incorporates the "applicable emission limits, work practice standards, and operating limits in 40 CFR 63 Subpart DDDDD" for the Ammonia Synthesis Loop Startup Heater. For the exact same reasons discussed above, this incorporation by reference is improper, and LDEQ must revise the permit to (1) include the specific "emission limits, work practice standards, and operating limits" from Subpart DDDDD that apply to the Ammonia Synthesis Loop Startup Heater in the text of the permit itself; and (2) revise the permit to reference only the specific parts of Subpart DDDDD that actually apply to this unit.

iv. The Standby Generators (EQT 19, EQT 20, EQT 24)

Conditions 85 through 102 of the Draft Title V Permit contain the common requirements that apply to the three Standby Generators (EQTs 19, 20, and 24). Conditions 85 and 86 improperly incorporate the requirements of 40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition ["CI"] Internal Combustion ["ICE"] Engines.

Condition 85 states that CFI shall:

> Comply with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power. Subpart IIII. [40 CFR 60.4205(b)]

While Condition 86 states that CFI shall:

> Operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 and 40 CFR 60.4205 over the entire life of the engine. Subpart IIII.

Draft Title V Permit Conditions 85, 86.

Neither of these conditions state the emission standards that apply to these units, or provide a citation to the specific provisions of Subpart IIII that list these requirements. The provisions of Subpart IIII cited by these conditions—40 CFR 60.4204, 40 CFR 60.4205, and 40 CFR 60.4205(b)—are again only high-level citations to provisions which contain many different potential requirements that only apply to emission units meeting certain criteria.

For all of the units described above, there is no reason for the permit to fail to state the applicable emission limits or to cite to the specific sections of the relevant subparts that apply. These omissions and improper incorporations by reference are especially puzzling, given that there are multiple examples of *proper* incorporations by reference, where LDEQ has done both, elsewhere in the permit—including for other similar units subject to the same Subparts as the units described above. For example, Draft Title V Permit Conditions 57, 58, and 59, which incorporate specific emission limits for VOC, CO, and NOx from Subpart IIII that are applicable to the Firewater Pumps, both list the precise numerical limits and expressly cite to the specific provisions of Subpart IIII that are applicable to the pumps where these limits may be found. Similarly, Conditions 37, 38, and 39 incorporate emission limits from Subpart JJJJ that apply to Standby Generators 1 and 2, and each condition states the precise numerical limit and provides a citation to the exact provision of Subpart JJJJ that applies. These indicate that LDEQ knows how to incorporate requirements from federal regulations properly, and it is not clear why LDEQ has failed to do so for the units identified above.

Forcing regulators and the public to exhaustively review entire federal Subparts simply to figure out what emission limits apply to a unit would contravene the entire purpose of Title V, and the permit as drafted cannot be said to include or assure compliance with the applicable requirements of the subparts referenced. In each instance where the Draft Title V permit contains a condition requiring a unit to comply with the emission limits and standards listed in a federal regulation, LDEQ must revise the Draft Title V permit to (1) clearly state the specific emission limits, work practice standards, and/or operating limits that apply in the condition itself, and (2) revise the permit to reference the specific parts of the relevant Subpart that apply to the unit(s) in question. Further, for any requirements incorporated from PSD-LA-859, LDEQ must also revise the Draft Title V Permit to make clear that PSD-LA-859 is the origin of those requirements.

These should all be relatively minor fixes on LDEQ's part. However, the deficiencies they address are serious, and the Draft Title V Permit cannot be issued without addressing them.

B. LDEQ must revise the Draft Title V permit's "Emission Rates" tables to make explicitly clear what hourly and annual emission limits apply to each unit—and what the basis for each limit is.

LDEQ's Statement of Basis states that: "Permitted limits for individual emissions units and groups of emissions units, if applicable, are set forth in the tables of the proposed permit entitled 'Emission Rates for Criteria Pollutants' and 'Emission Rates for TAP/HAP & Other Pollutants.'" Draft Permit Package at 93. These two tables are on pages 25-29 and pages 30-32 of the Draft Permit Package, respectively. As drafted, however, it is impossible to discern from these tables which hourly emission limits apply to each of the Facility's emission units, and when. Specifically, the "Emission Rates for Criteria Pollutants and CO2e" table lists "tons/year"

emission rates, as well as both "average" hourly emission rates **and** "maximum" hourly emission rates, for each unit. Because these tables list both "average" and "maximum" hourly emission rates, it is impossible to discern which emission rate is actually the enforceable emission limit, whether certain emission rates are enforceable under different circumstances, or if *neither* of these emission rates are enforceable limits.

As an initial matter, it is substantially unclear whether *any* of the emission rates listed in these tables are federally enforceable, including the annual "tpy" limits. It appears that in all cases, the annual "tpy" limits are identical to the annual PTEs used for each unit in the PSD applicability analysis, and that these tpy limits have been calculated using their "average" hourly emissions rather than their "maximum" hourly emission rates. For example, for the CO2 Vent (RLP 0004, VNT-CO2) the Emission Rates table lists both an "average" hourly VOC emission rate of 59.36 pounds per hour ("lb/hour") and a "maximum" emission rate of 80.32 lb/hour, as well as an annual emission rate of 28.60 tons per year ("tpy"). Draft Permit Package at 28. Commenters presume that at a minimum LDEQ intended the 28.60 tpy "emission rate" to be an enforceable emission limit because that is the number that CFI and LDEQ used as the CO2 Vent's potential to emit ("PTE") for purposes of major source PSD applicability. And it should naturally follow that the "average" emission rate of 59.36 lb/hour should also be an enforceable emission limit, because the permit record shows that this was the hourly rate used to calculate that 28.60 tpy. However, the fact that this is labeled as an "average" emission rate, and that the table also includes a "maximum" hourly emission rate of 80.32 lb/hour, implies that the "average" rate in fact is *not* an enforceable emission limit. And if the maximum hourly rate is a separate hourly limit, it is unclear from the table under what circumstances it applies.[107]

A review of the Draft PSD Permit shows that at least some of the "maximum" hourly emission rates listed in the Draft Title V Permit's Emission Rates tables are listed as requirements of the Draft PSD Permit. However, the Draft PSD Permit only lists "maximum" hourly emission rates as requirements and never mentions "average" hourly emission rates—strongly indicating that the average hourly emission rates are not in fact enforceable emission limits. We also note that the Draft PSD Permit does not contain any emission limits for either VOCs or PM10/PM2.5, making it substantially unclear what the origins are for the VOC and PM10/PM2.5 emission rates found in the emission rates tables, or how LDEQ calculated them.[108] For example, for PM10 and PM2.5 emissions the Emission Rates table states the Auxiliary Boiler (EQT 11) has an "average" hourly emission rate of 3.38 lb/hr, a "maximum" hourly emission rate of 4.22 lb/hr, and an annual emission rate of 7.39 tpy. None of these emission rates are mentioned in either the Draft PSD Permit or the specific requirements applicable to the Auxiliary Boiler (Conditions 103-137), leaving it unclear what the origin of these emission rates are or how they were calculated.

---

[107] We also note that some units, such as the CRG 2 Heaters (EQT 5 & 28), have a "maximum" hourly rate listed in the table, but no average hourly rate—or annual tpy rate.

[108] It is also unclear how LDEQ calculated some of the other lb/hour emission rates listed in this table, as they do not seem to match directly with their BACT counterparts. For example, the Emission Rate table states an average hourly CO emission rate of 37.31 lb/hour for the Auxiliary Boiler, while the PSD permit states that the CO BACT rate is 0.083 lb/mmBtu. At the boiler's stated average operating rate of 453 mmBtu, the BACT rate translates to an average hourly mass emission rate of 37.6 lb/hour—which is noticeably higher than the table's stated emission rate.

In fact, almost none of the emission rates listed in the "Emission Rates" table are incorporated into the "Specific Requirements" section, which lists the requirements applicable to each unit, and the specific requirements for the vast majority of these units do not reference these limits—and in nearly all cases, do not contain any monitoring, reporting, or testing requirements that either reference or could be used to determine compliance with those limits. For example, Title V Permit Conditions 157-159, which list out the specific requirements for the CO2 Vent, make no reference to any hourly emission limit at all, and do not appear to contain any testing, monitoring, or reporting requirements that could be used to determine compliance with an hourly limit (either the "average" or "maximum").

Clarifying precisely which of these emission rates are actually intended to be federally enforceable limits (if any) is extremely important because, as discussed at length in Section I.A of these comments, the law is very clear that *only* federally enforceable limits may be used to restrict PTE. For example, if the only enforceable hourly VOC emission limit for the CO2 Vent is the listed "maximum" emission rate of 80.32 lb/hour, CFI and LDEQ *must* use this emission rate to calculate PTE, rather than the "average" emission rate of 59.36 lb/hour—and this has immediate consequences for CFI's PSD applicability analysis, as it would push CFI's emissions substantially above the PSD major threshold of 40 tpy and necessitate a full BACT analysis for VOCs.

Further, as noted above, it appears that CFI calculated all of the "tons/year" emission rates listed in the Emissions Rates table using the "average" hourly emission rate, rather than the "maximum" hourly emission rate. These "annual" tpy emission rates were also used for CFI's PTE estimates for PSD applicability. If the "average" hourly emission rates listed in the Emission Rates tables are *not* enforceable emission limits, then *all* of CFI's PTE calculations are incorrect across the board and must be revised upwards using the "maximum" hourly rates. This would also result in CFI exceeding the major PSD thresholds for PM10 and PM2.5, which it is currently barely below (0.88 tpy below the threshold for PM10, and 0.30 tpy below the threshold for PM2.5), necessitating a full PSD and BACT analysis for these pollutants. The Emission Rates table states the Auxiliary Boiler has an "average" hourly emission rate of 3.38 lb/hr, a "maximum" hourly emission rate of 4.22 lb/hr, and an annual emission rate of 7.39 tpy. As an initial matter, we also note that the annual PTE for the Auxiliary Boiler appears to have been calculated not only using the hourly average emission rate rather than the maximum hourly rate, but also using 4,380 hours of operation per year:

3.38 lb/hr x 4,380 hours = 14,804.4 lbs/year = 7.4 tpy.

Nothing in the Draft Title V Permit or the Statement of Basis explains why the PTE for the Auxiliary Boiler was calculated using only 4,380 hours of operation. Because the Draft Title V Permit does not contain any condition limiting hours of operation for the Auxiliary Boiler, it is impermissible to use 4,380 hours rather than a full 8,760 hours to calculate PTE. Even putting aside that issue, simply using the "maximum" hourly emissions rate to calculate the Auxiliary Boiler's PM10/2.5 emissions would result in CFI triggering the major PSD threshold, thereby necessitating full air quality impact and BACT analyses for PM10/2.5:

4.22 lb/hr x 4,380 hours = 18,483.6lbs/year = 9.24 tpy.

Finally, the Emission Rates table also includes a number of instances where a unit's average hourly, maximum hourly, and/or tons per year emission rates simply state "<0.01" lb/hr or tpy. In some cases, the Emission Rates table states <0.01 for all three. For example, all the hourly and annual emission rates for PM10/2.5 and SO2 from the Synthesis Gas Flare and Ammonia Flare (EQT 3, 4) are listed as "<0.01." The annual "<0.01" tpy

To be clear, Commenters are not suggesting that it is impermissible as a rule to list a facility's enforceable emission limits in the form of a summary table. We note that some states do include a table of maximum emission rates in their Title V permits. For example, the State of Texas typically includes a "Maximum Allowable Emission Rates Table," or MAERT, in its Title V permits. However, two major factors distinguish between that practice and what LDEQ has done here. First, those tables only include **one** hourly emission rate and makes clear that this is the "maximum **allowable** emission rate" (emphasis added).[109] If different hourly emission rates apply at certain times or operational conditions, the tables make this clear by including a separate row that clearly demarcates this. They do not simply list an array of different rates—some labeled "average" and some labeled "maximum"—and leave it up to the public to puzzle out which emission rate (if any) might be enforceable, or when.

Second, these permits also either reiterate the emission limit in the specific conditions for the relevant unit or specifically cite to the limit in the emission table, because the unit-specific conditions will also list the monitoring, reporting, and testing requirements that are necessary to demonstrate compliance with the limit in question. The Title V permit here not only fails to list the "emission rates" for the CO2 Vent in the specific conditions applicable to the unit, but also fails to include *any* monitoring, testing, or reporting requirements associated with these limits—making it more or less impossible to verify compliance with those limits.

As drafted, it is impossible to determine which of the "emission rates" listed in the Title V Permit's "emission rate" tables are intended to be enforceable emission limits—or indeed, whether any of the listed emission rates are intended to be enforceable limit.[110] LDEQ must revise the permit to make it explicitly clear which of these rates, if any, are enforceable emission limits. And if the "average" hourly emission rates are **not** in fact enforceable emission limits, LDEQ must either (1) revise the Draft Title V Permit to include strict and enforceable limits to ensure that these units will not exceed their quoted annual PTE limits, or (2) require CFI recalculate its annual PTE emissions across the board using the "maximum" hourly emission limits.

---

[109] *See generally* TCEQ, Maximum Allowable Emission Rates Table accompanying Permit Numbers 174275 and PSDTX1628 for the Ingleside Blue Ammonia plant. Available at: https://records.tceq.texas.gov/cs/idcplg?IdcService=TCEQ_APD_SEARCH_GET_FILE&xAPDParent=7241511&SearchID=15108672&searchType=External

[110] In multiple instances, the Title V permit also incorporates limits contained in federal regulations by reference by citing the entire regulation subpart (e.g., by citing "40 CFR 63 Subpart DDDDD.") This is not a proper way to incorporate requirements by reference, as it leaves it substantially unclear what the applicable requirements being incorporated are. These are discussed further in Section II.D of these comments, which discusses the specific requirements for each unit in turn.

C. The Draft Title V Permit impermissibly authorizes "commissioning" emissions, and also impermissibly excludes these emissions from PTE.

For multiple units, the Draft Title V Permit purports to authorize additional emissions beyond the permitted hourly and annual limits during a 1-year "commissioning" period. Each of these conditions contain identical language, and each state:

> For a period of one year after initial startup of the facility, it is expected that there will be a commissioning period which will require additional emissions from cold starts, startups, shutdowns, and CO2 pipeline commissioning. During the commissioning period, the commissioning scenario emissions in addition to the proposed annual emissions are authorized… as follows…

Draft Title V Permit Conditions 5, 29, 134, 147, 158.

The proposed commissioning limits do not comply with the requirements of the Clean Air Act, for three reasons:

(1) The Clean Air Act is clear that all emissions, including emissions during a "commissioning" period, must be included in PTE.
(2) LDEQ does not have the authority to include alternate limits for "commissioning" periods; and
(3) LDEQ has not explained the basis for how these "commissioning" emissions have been calculated.

The applicable units include the Synthesis Gas Flare (EQT 3), Ammonia Gas Flare (EQT 4), Steam Superheater (EQT 5), Fired Process Heater (EQT 28), Auxiliary Boiler (EQT 11), Ammonia Synthesis Loop Startup Heater (EQT 29), and the CO2 Vent (VNT-CO2**).** The annual emissions authorized in these conditions are listed in the table below.

"Commissioning Emissions" in tpy

Unit	Condition	PM10	PM2.5	SO2	NOx	CO	VOC	Ammonia
Syngas Flare & Ammonia Gas Flare	**5**	<0.01	<0.01	<0.01	213.74	466.21	1.02	40.52
Steam Superheater & Fired Process Heater	**29**	1.40	1.40	0.11	30.89	17.46	1.02	10.21
Auxiliary Boiler[111]	**134**	7.39	7.39	0.58	19.51	81.70	5.35	8.03

[111] Condition 134 also authorizes very minor annual emissions of a number of TAPs from the Auxiliary Boiler.

Ammonia Synthesis Loop Startup Heater	**147**	0.05	0.05	<0.01	0.31	0.52	0.03	-
CO2 Vent	**158**	-	-	-	-	26.80	260.01	246.60

Commenters note that it is not clear from the text of these conditions precisely what "commissioning" emissions are being authorized—specifically, whether these conditions are intended to authorize commissioning emissions in *excess* of the regular annual tons per year emission rates identified in the Emission Rates tables on pages 23-30 of the Draft Title V Permit. Though these conditions each state that during the commissioning period, the commission scenario emissions *in addition* to the proposed annual emissions are authorized, with the sole and notable exception of the CO2 Vent it appears that the annual tpy emissions listed in each condition are the same as the annual tpy emission rates listed in the Emission Rates tables.

From a review of the estimated emission rates during the commissioning period provided for each of these units in CFI's permit application materials, it appears as though for at least some units—specifically, the two flares and the Ammonia Synthesis Loop Startup Heater—the estimated maximum hourly emission rate during the commissioning period appears to be the same as the maximum hourly emission rate in the Emission Rates tables, but "average" hourly emission rates estimated during the commissioning period are *substantially* higher than the "average" hourly rates listed in the Emission Rates table. Draft Permit Package at 355-365. For the Steam Superheater, the Fired Process Heater, and the Auxiliary Boiler, the maximum hourly emission rates that CFI estimated for the commissioning period, Draft Permit Package at 351-354, are the same as the "maximum" hourly emission rates listed for the maximum hourly emission rates listed in the Emission Rates tables for their "startup" scenarios (22B001 SU, 13B001 SU, and 23U510 SU). Draft Title V Permit Conditions 160-166, which apply to the Steam Superheater, Fired Process Heater, and Auxiliary Boiler during "startup," establish BACT emission limits of 0.083 lb/mmBtu for CO and 0.14 lb/mmBtu for NOx for each of these units, which appear to have been the emission rates used to calculate the "maximum" hourly emission rates identified for startup conditions. Piecing this together suggests to Commenters that LDEQ's intent may have been to authorize alternate, substantially higher *hourly* emission rates during the commissioning period, but *not* to authorize additional emissions on an annual basis (with the exception of the CO2 Vent). In other words, these conditions allow for higher short-term limits during commissioning, but require CFI to meet the identified annual tpy limits at all times, regardless of whether the emissions occur during commissioning or non-commissioning periods. However, the Draft Permit is not at all clear exactly what emission limits apply during the commissioning period, and this level of ambiguity with respect to permit requirements is simply not allowed under the Clean Air Act.

Again, because LDEQ has provided absolutely no explanation in the record regarding the origin or method by which the emission rates in the Emission Rates tables were calculated, or when the "startup" conditions apply, it is impossible for Commenters to know for certain, and Commenters can only speculate as to what "additional" emissions these conditions are intended to authorize, or what limit applies when. At a bare minimum, Commenters would expect LDEQ

to clarify precisely what these proposed "additional" emissions are, and what limits they propose actually apply during the commissioning period (if any). Regardless, the proposed commissioning limits do not comply with the Clean Air Act for several reasons.

1. <u>All emissions, including "startup emissions," must be included in PTE.</u>

Both the Clean Air Act and Louisiana's SIP are unambiguous that all emissions, including emissions during periods of SSM, must be included in both actual emissions and calculations of PTE.

LAC 33:III.509.B defines "Potential to Emit" as:

> [T]he maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

The definition of "potential to emit" noticeably does not mention "commissioning emissions" or contemplate an exception for "commissioning emissions." While the definition does permit an exclusion for "secondary emissions," this term has a very specific and narrow definition, and only includes:

> [E]missions which would occur as a result of the construction or operation of a major stationary source or major modification, but **do not come from the major stationary source or major modification itself**.

LAC 33:III.509.B (emphasis added).

Because "commissioning" emissions undeniably come from the source itself, they plainly do not meet the definition of secondary emissions—and therefore are not included in the very narrow universe of emissions that may be excluded from PTE. Further, there is no distinction between "startup" emissions and "commissioning" emissions. The Louisiana SIP defines "start-up" as the "setting in operation of an affected facility for any purpose." LAC 33:III.111.A.

As noted above, for most of the units in question it is not entirely clear to Commenters whether LDEQ intended to actually authorize any emissions beyond the units' stated annual tpy used as the basis for CFI's PTE calculations, as the relevant conditions appear to simply replicate the annual tpy emission rates listed in the Emission Rates tables. However, even if that is the case, two serious concerns remain.

First, as discussed at length in Section I.A of these comments, both the definition of PTE itself, as well as EPA's guidance and federal court precedents interpreting the same, make clear that PTE must reflect the maximum emissions of the source operating at full design capacity, and

that this may only be restricted by federally enforceable production or operational limit that actually restricts the capacity of the source itself to emit. 1989 PTE Guidance at 6; *United States v. Louisiana-Pac. Corp.,* 682 F. Supp. 1122, 1132 (D. Colo. 1987). As noted previously, CFI and LDEQ appear to have calculated the annual tpy emission rates in the Emission Rates tables using the "average" hourly emission rates listed in the table. However, by definition, the maximum hourly emission rates that are apparently authorized during the commission period represents the unrestricted PTE of these units. For example, the Draft Title V Permit establishes maximum "startup" hourly emission rates for the Steam Superheater, the Fired Process Heater, and the Auxiliary Boiler (22B001 SU, 13B001 SU, and 23U510 SU) that are **substantially** higher than their normal "maximum" hourly rates. The Emission Rates table, however, lists very low annual tpy emission rates for each. We assume this low tpy emission rate is calculated based on an assumed limited number of hours operation per year for startup. However, this is not a valid limitation on PTE because the Draft Title V Permit does not actually contain any **requirement** to limit these units' hours of operation during startup. Because the Draft Title V Permit simply establishes annual tpy limits and does not include any enforceable production or operational limits that would also restrict emissions during the commissioning period, PTE **must** be calculated using the maximum hourly emission rate authorized for commissioning periods—**not** the "average" hourly emission rate.

Second, as noted above, Draft Title V Permit Condition 158 in fact clearly authorizes annual tpy limits for CO, VOCs, and ammonia that are **substantially** higher than the annual tpy emission rates listed in the Emission Rates tables. As discussed in Section I.A, these "commissioning" period annual tpy are in fact the actual PTE emissions for the CO2 Vent that **must** be used for PSD applicability determination, because these emission rates represent the CO2 Vent's actual capacity to emit before (improperly) excluding the reductions claimed by CFI from its assumed 89% CCS capture rate.

Although LDEQ may attempt to assert that these emissions qualify as "temporary" emissions, these emissions are not "temporary." As explained above, the maximum hourly "commissioning" emission rates for each of these units, as well as the annual tpy "commissioning" emission rates for the CO2 Vent, in fact represent the maximum PTE of these units at their **design capacity**, absent any production or operational limits. However, whether they are temporary emissions or not makes no difference—they must be included in PTE either way. As the United States Court of Appeals for the Tenth Circuit has very recently held, the definition of "potential to emit" expressly does *not* include any exemption for "temporary" emissions, and such emissions *cannot* properly be excluded from a facility's PTE for purposes of determining major PSD applicability. *Ctr. for Biological Diversity v. U.S. Env't Prot. Agency,* 82 F.4th 959, 967–68 (10th Cir. 2023) (explicitly rejecting state's proposed PTE definition that purported to exclude temporary emissions and holding that "EPA acted contrary to law in allowing Colorado to exclude all temporary emissions.").

The maximum emission rates for the commissioning period represent these units' maximum capacity to emit at their unrestricted design capacity. LDEQ must either require CFI to redo its PSD applicability analysis with PTE rates recalculated using these higher emission rates, or revise the permit to include strict, enforceable limits that will ensure that CFI does not exceed

the average hourly emission rates that CFI relied upon to calculate its annual tpy emission rates, both for periods of commissioning and non-commissioning.

2. LDEQ cannot authorize alternate limits for a "commissioning period" through the draft Title V permit.

As noted above, it is unclear whether LDEQ has the authority to authorize alternate "commissioning" limits at all, and the permit record does not make clear what authority LDEQ is relying upon to authorize these additional "commissioning" emissions. It is notable that the Draft PSD Permit does not authorize commissioning emissions—or even reference a commissioning period at all—and that the provisions related to commissioning emissions are *only* included in the Draft Title V Permit. Even assuming LDEQ could authorize additional emissions during the commissioning period, it certainly cannot do so through a Title V Permit—at a minimum, these limits must be established clearly in the Draft PSD Permit.

The only source of authority cited by Draft Title V Permit Conditions 5, 29, 134, 147, 158 to authorize these additional limits is LAC 33:III.501.C.6. This provision states:

> The permitting authority shall incorporate into each permit sufficient terms and conditions to ensure compliance with all state and federally applicable air quality requirements and standards at the source and such other terms and conditions as determined by the permitting authority to be reasonable and necessary. It is the intent of this regulation that suitable controls be applied to new installations and relocations and in cases where modifications are to be made or where significant changes in emissions are anticipated.

This provision merely states a general requirement that LDEQ ensure that each permit includes any and all requirements necessary to assure compliance with all state and federal requirements. This provision certainly does not grant LDEQ the authority to allow "additional" emissions during commissioning periods far in excess of permitted limits.

3. Nothing in the permit record provides a justification for why additional emissions during a commissioning period are necessary.

Finally, nothing in the permit record actually provides an explanation for *why* it is necessary or justified to authorize additional emissions during a commissioning period at all or whether these additional emissions will impact air quality. CFI's initial application states that "[d]uring the commissioning process, some sources require testing and fine -tuning to ensure functionality and efficiency. This may result in extended periods with higher-than-normal emissions[.]" Draft Permit Package at 118. This is all the information that CFI provided in its application, and appears to be the *only* time that the commissioning period is directly addressed anywhere in the permit record. LDEQ does not appear to have asked any follow-up questions, but merely adopted CFI's proposed emission limits for the commissioning period as a matter of course. *See* Draft Permit Package at 508 (simply noting "Change made as requested" to each of CFI's proposed conditions authorizing emissions during a commissioning period).

LDEQ bears the burden of ensuring that the Draft Title V Permit contains "sufficient terms and conditions to ensure compliance with all state and federally applicable air quality requirements and standards at the source and such other terms and conditions as determined by the permitting authority to be reasonable and necessary." LAC 33:III.501.C.6. In all cases, LDEQ's rationale for its decision and its factual findings must be clear and documented in the permit record. *Save Ourselves v. La. Envt'l. Control Comm'n*, 452 So.2d 1152, 1160 (La. 1984). LDEQ cannot simply rubberstamp CFI's request for higher emission limits, but must provide a clear explanation for *why* it is necessary or justified to authorize additional emissions during a commissioning period and ensure these additional emissions will not adversely impact air quality.

D. The Draft Title V Permit does not contain testing or monitoring requirements adequate to assure continuous compliance with most of the hourly and long-term emission limits at each unit.

"Each permit issued under [Title V] shall set forth inspection, entry, monitoring, compliance certification, and reporting requirements to assure compliance with the permit terms and conditions." 42 U.S.C. 7661c(c); LAC 33:III.507.H.1; 40 C.F.R. 70.6(c)(1). Louisiana's SIP requires that where an applicable requirement does not require periodic testing or instrumental or non-instrumental monitoring, the permit must include:

> …periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit, as reported pursuant to 40 CFR 70.6(a)(3)(iii). Such monitoring requirements shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement.

LAC 33:III.507.H.1.a.

It is LDEQ's responsibility, as the relevant permitting authority, "to ensure that the [T]itle v permit 'set[s] forth' monitoring to assure compliance with all applicable requirements" of the Clean Air Act.[112] Further, any emission limit in a Title V permit must be enforceable as both a legal and practical matter. For a limit to be enforceable as a practical matter, a proposed permit must clearly specify how emissions will be measured or determined for purposes of demonstrating compliance with the limit.[113] This requires that any proposed emission limits "be accompanied by terms and conditions that require a source to effectively constrain its operations so as to not exceed the relevant emissions threshold… whether by restricting emissions directly or through restricting specific operating parameters," and supported by monitoring, recordkeeping, and reporting requirements "sufficient to enable regulators and citizens to

---

[112] *In the Matter of Sandy Creek Services, LLC, Sandy Creek Energy Station, McLennan County, TX*, EPA Order on Petition No. III-2018-1 (June 30, 2021) at 12 (quoting 42 U.S.C. 7661c(c)). Available at: https://www.epa.gov/system/files/documents/2021-07/sandy-creek-order_06-30-21.pdf

[113] *See, e.g.*, *In the Matter of Hu Honua Bioenergy Facility, Pepeekeo, HI*, Order on Petition No. IX-2011-1 (Feb. 7, 2014) at 10. Available at: https://www.epa.gov/sites/default/files/2015-08/documents/hu_honua_decision2011.pdf

determine whether the limit has been exceeded and, if so, to take appropriate enforcement action."[114]

As a general matter, "the time period associated with monitoring or other compliance assurance provisions must bear a relationship to the limits with which the monitoring assures compliance."[115] As recent EPA Title V orders have explained, this generally includes demonstrating a match "between the time frame of the emission limits and the Permit's compliance assurance provisions." Clairton Order at 10. However, determining whether monitoring contained in a title V permit is sufficient to assure compliance with any term or condition is a context-specific, case-by-case inquiry. *Id.* at 9. To aid permitting authorities and the public in this fact-specific exercise, EPA has identified a non-exhaustive list of factors that that permitting authorities "may consider as a starting point in determining appropriate monitoring" for a facility, including: (1) the variability of emissions from the unit in question; (2) the likelihood of a violation of the requirements; (3) whether add-on controls are being used for the unit to meet the emission limit; (4) the type of monitoring process, maintenance, or control equipment data already available for the emission unit; and (5) the type and frequency of the monitoring requirements for similar emission units at other facilities. *Id.*

"In all cases, the rationale for the selected monitoring requirements must be clear and documented in the permit record." *In the Matter of CITGO Refining and Chemicals Co., L.P., West Plant, Corpus Christi, TX, Order on Petition No. VI-2007-01* (May 28, 2009) ("CITGO Order")[116] at 7 (granting petition because permitting authority "did not articulate a rationale for its conclusions that the monitoring requirements… are sufficient to assure compliance"); *see also* 40 C.F.R. 70.7(a)(5).

The Draft Title V permit lacks testing and monitoring requirements adequate to assure continuous compliance with numerous hourly and long-term emission limits applicable to multiple units at the Facility, including a significant number of the hourly and long-term emission rates in the "Emission Rates" tables.

1. Nearly all of the emission rates listed in both "Emission Rates" tables appear to have no associated testing or monitoring conditions.

LDEQ's Statement of Basis states that: "Permitted limits for individual emissions units and groups of emissions units, if applicable, are set forth in the tables of the proposed permit entitled 'Emission Rates for Criteria Pollutants' and 'Emission Rates for TAP/HAP & Other Pollutants.'" Draft Permit Package at 93. These two tables are on pages 25-29 and pages 30-32

[114] *In the Matter of Orange Recycling and Ethanol Production Facility, Pencor-Masada Oxynol, LLC*, EPA Order on Petition No. II-2001-05 (Apr. 8, 2002), at 7. Available at: https://www.epa.gov/sites/default/files/2015-08/documents/masada-2_decision2001.pdf
[115] *In the Matter of United States Steel Corporation, Clairton Coke Works Permit No. 0052-OP22*, Order on Petition Nos. III-2023-5 and III-2023-6 (Sept. 18, 2023) ("Clairton Order") at 9; *see also* 40 C.F.R. 70.6(a)(3)(i)(B). Available at: https://www.epa.gov/system/files/documents/2023-10/us-steel-clairton-order_9-18-23.pdf
[116] Available at: https://www.epa.gov/sites/default/files/2015-08/documents/citgo_corpuschristi_west_response2007.pdf

of the Draft Permit Package, respectively. As discussed, it is unclear precisely which of these emission rates are actually intended to be enforceable emission limits. This is especially unclear because almost none of the emission rates listed in either table—whether average hourly, maximum hourly, or tons per year—appear to have any associated monitoring, reporting, or testing requirements. For some units, the Specific Requirements section lists requirements that *could* be relevant to assuring continuous compliance with those units' emission limits, such as a general requirement to conduct periodic tune-ups or stack tests. However, neither these conditions nor anything else in LDEQ's Statement of Basis or permit materials explains *how* these requirements actually relate to the specific emission limits in question, or how they are sufficient to assure compliance with those limits.

Each limit applicable to each unit or group of units will be examined in turn below. Commenters acknowledge that for some of the units, the potential emissions for certain pollutants are not especially high as the limits in question are very low. However, this does not mean that LDEQ can simply neglect its obligation to assure that these units are meeting their permitted emission limits, and certainly does not justify a failure to include *any* monitoring or testing requirements for the vast majority of these limits—especially given that CFI is relying on some of these hourly limits as the basis for calculating PTE for its PSD applicability analysis. EPA very recently objected to a Title V permit that failed to include any monitoring or testing requirements in part on the grounds that testing was not required because actual emissions were expected to be quite low, and the limits in question were similarly low. As EPA stated:

> In general, it may be reasonable for a permitting authority to consider, among other things, the magnitude of emissions and the economic and technical feasibility of different testing and monitoring requirements when determining which compliance assurance requirements to impose in a title V permit. However, any such considerations must be evaluated in the appropriate context: determining which requirements are necessary to assure compliance with all applicable requirements and permit terms… **the fact that an emission limit is relatively low does not, in and of itself, mean that compliance with such limit can be assured with less testing or without monitoring**. To the contrary, in some cases, a low emission limit *(e.g.,* one that substantially restricts a facility's emissions) may be associated with a high likelihood of violation, giving rise to the need for more stringent testing or monitoring.

In the Matter of Neville Chemical Company, Permit No. 0060-OP24, Allegheny County, PA, EPA Order on Petition No. III-2024-22 (Sept. 16, 2025) ("Neville Order") at 14 (emphasis added).[117]

Thus, while Commenters acknowledge that some of these emission limits are relatively low, this does not relieve LDEQ of its duty to ensure that the Draft Title V Permit contains sufficient terms, including monitoring and testing requirements, to assure compliance with those limits. The Draft Title V Permit establishes short- and long-term emission limits, and these limits are not meaningless—there must be some mechanism for assuring continuous compliance with these limits. If LDEQ believes that a specific design or operational requirement, such as the

[117] Available at: https://www.epa.gov/system/files/documents/2025-09/neville-order_9-16-25.pdf

requirement to use a specific type of fuel or the requirement to use equipment certified for a specific standard, is sufficient to assure compliance with a particular limit, that may be sufficient—however, LDEQ must make the connection between the requirement and the limit clear, and clearly explain its rationale in the permit record.

a. *Synthesis Gas Flare and Ammonia Flare (EQT 3, 4)*

i. Applicable emission limits

The Emission Rate tables list the following "emission rates" for criteria pollutants and ammonia from these two flares.

Syngas Flare (EQT 3)

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	5,007.00
PM10	<0.01	<0.01	<0.01
PM2.5	<0.01	<0.01	<0.01
SO2	<0.01	<0.01	<0.01
NOx	42.18	403.94	184.75
CO	106.19	5019.37	465.11
VOC	0.23	51.10	1.00
Ammonia	0.15	15.97	0.64

Ammonia Gas Flare (EQT 4)

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	369
PM10	<0.01	<0.01	<0.01
PM2.5	<0.01	<0.01	<0.01
SO2	<0.01	<0.01	<0.01
NOx	6.62	143.98	28.99
CO	0.25	0.32	1.10
VOC	<0.01	0.01	0.02
Ammonia	9.11	199.42	39.88

None of these emission rates are referenced in the specific requirements for these units, and the specific requirements do not contain any specific requirements to monitor, test, or demonstrate compliance with these limits. *See* Conditions 1-11. Further, Condition 5 establishes annual emission limits for the commissioning period, which appear identical to the annual emission rates listed in the tables—but Condition 5 does not require any monitoring or testing, and does not explain how compliance with these annual limits will be measured or demonstrated.

Conditions 1, 2, and 7 require these flares to meet a 20% opacity limit and conduct daily visual inspections to determine compliance with this limit.

ii. Monitoring and testing requirements

Condition 11 states that "BACT for NOx, CO, and CO2e emissions from the flares is determined to be combination of proper design and operation and good combustion practices, including establishment of flare minimization practices." Condition 6 requires CFI to "operate the flare at all times when emissions are vented to the flare," while Conditions 8-9 generally require monitoring and recordkeeping for the presence of a flame. Condition 10 states that CFI shall continuously monitor and record the volume of vent gas routed to the flare. Nothing in the permit materials explains how these conditions actually relate to, let alone assure continuous compliance with, the hourly or annual emission limits applicable to the flares.

iii. Adequacy of monitoring and testing

Aside from the visual opacity inspections and general requirement to monitor flame presence, the Draft Title V Permit apparently contains no testing or monitoring requirements at all for emissions of any pollutants these flares.

The permit does *not* include any limits, testing, or monitoring requirements related to a number of typical indicators of flare performance, such as destruction efficiency ("DRE"), net heating value, or inlet gas content. These omissions are especially puzzling since the permit materials indicate that CFI and LDEQ are aware that these parameters are likely to have a significant impact on emission rates. For example, CFI's Revised Permit Application states that it assumed a 98% destruction efficiency for these flares for CO, CO2, Ammonia, and VOCs, and that ammonia emissions "result from uncombusted ammonia in flared gas streams based on the flare destruction efficiency." *See* Draft Permit Package at 251, 259. Yet despite this, the Draft Title V Permit does not require CFI to meet a minimum flare DRE of 98%, or even to monitor or report its DRE. The Draft PSD Permit's BACT analysis for these flares also does not mention a specific minimum DRE and simply states that "[p]roper design and operation assures high reliability of the flare and high destruction efficiencies." Draft Permit Package at 68. The Draft PSD Permit also states that "[g]ood flare design includes pilot flame monitoring and monitoring/control of the waste gas heating value." *Id.* Yet again, the permit contains no operating limits, monitoring, or reporting requirements related to heating value. Similarly, the Revised Permit Application also states that an estimated 0.5% of inlet ammonia in these flared gas streams are expected to be converted to NOx emissions. Draft Permit Package at 251, note 1. While Condition 10 requires CFI to monitor the volume of vent gas routed to these flares, these specific conditions do not appear to require CFI to monitor or report inlet ammonia.

If it's LDEQ's position that the current conditions are sufficient to assure compliance with each of the hourly and annual limits for these flares, LDEQ must at a minimum explain clearly in the permit record how these conditions relate to the emission limits and why it believes they are adequate to assure continuous compliance with the limits. Adequate testing and monitoring requirements are especially important for these units, because together they account for the majority of NOx and CO emissions from this Facility, as well as a very significant portion of the Facility's projected ammonia emissions.

b. *CRG 2 Heaters (EQT 5, 28)*

i. Applicable emission limits

The Emission Rate tables list the following "emission rates" for criteria pollutants and TAPs/HAPs from these two heaters.

Steam Superheater (EQT 5)

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	-
PM10	-	0.17	-
PM2.5	-	0.17	-
SO2	-	0.01	-
NOx	-	3.90	-
CO	-	2.17	-
VOC	-	0.12	-
Ammonia	-	1.60	-
Formaldehyde	-	<0.001	-
n-Hexane	-	0.002	-
Zinc and compounds	-	<0.001	-

Fired Process Heater (EQT 28)

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	-
PM10	-	0.14	-
PM2.5	-	0.14	-
SO2	-	0.01	-
NOx	-	3.19	-
CO	-	1.77	-
VOC	-	0.10	-
Ammonia	-	1.31	-
Formaldehyde	-	<0.001	-
n-Hexane	-	0.001	-
Zinc and compounds	-	<0.001	-

Draft Permit Package at 26-29.

Each heater also has a requirement to limit total suspended particulate to no more than 0.6 lb/mmBtu, which Condition 28 states will be complied with by using sweet natural gas as fuel.

Condition 32 also establishes a CO BACT limit of 0.083 lb/mmBtu on a 30-day rolling average basis, with BACT for controlling emissions determined to be "good combustion

practices." Condition 33 establishes a NOx BACT limit of 9 ppmvd NOx @ 3% O2 on a 30-day rolling average basis, with BACT for controlling NOx emissions determined to be the combination of low-NOx burners and selective catalytic reduction ("SCR").

Finally, Condition 29 establishes annual emission limits for the 1-year commissioning period, of 1.40 tpy for PM10 and PM2.5, 0.11 tpy for SO2, 30.89 tpy of NOx, 17.46 tpy of CO, 1.02 tpy of VOCs, 10.21 tpy of ammonia, <0.01 tpy of formaldehyde, 0.01 tpy of n-hexane, and <0.01 tpy of zinc (and compounds). It is not clear how the annual emission limits for the criteria pollutants were calculated, as each of the annual emission limits appear to exceed the combined PTE of these units calculated using their maximum hourly emission rates.

ii. Monitoring and testing requirements

Condition 12 requires CFI to conduct a tune-up of each heater once every five years.

Condition 22 requires CFI to submit a report once every five years[118] of all the information required by Table 9 of Subpart DDDDD, and Condition 24 requires CFI to keep records of "the information specified in 40 CFR 63.7555(a) through (h), as applicable." Because Table 9, 40 CFR 63.7550, and 40 CFR 63.7555(a) through (h) list a wide range of information that a permittee may be required to submit depending on certain criteria and the Draft Title V Permit does not specify which specific requirements apply, it is unclear what precise information CFI is required to include in its reports or maintain records of under these conditions.

Conditions 30 and 31 establish general requirements to submit advance notifications to LDEQ of scheduled emission tests, and a requirement to submit results of any tests within 60 days. Condition 34 requires CFI to perform a performance test at each heater:

(1) Within 180 days of initial startup (or restart-up after modification);
(2) Within 60 days of achieving normal production of completing shakedown period; and/or
(3) Within 5 years, "plus or minus 6 months," from when the previous performance test was performed.

Condition 35 specifies that these performance tests shall be conducted using EPA Method 10 for determining CO emissions from stationary sources, and that such tests must be completed within 80 percent of maximum permitted load, or within 90% of "maximum achievable load."

Finally, Condition 36 requires CFI to install and operate continuous emission monitoring systems ("CEMS") at these heaters to measure NOx emissions.

iii. Adequacy of requirements

LDEQ should clarify how the use of sweet natural gas as fuel on its own is sufficient to assure compliance with Condition 28's total suspended particulate limit of 0.6 lb/mmBtu. (To be

[118] Though Condition 22 does not make this clear, a review of Table 9 and 40 CFR 63.7550 indicates that the frequency of reports matches that of required tune-ups—which these units are only required to perform once every five years.

clear, Commenters are not necessarily suggesting it is not sufficient, we are merely asking LDEQ to explain its rationale, as the permit currently does not provide an explanation for this).

Because Conditions 22-24 improperly incorporate Subpart DDDDD by reference, Commenters cannot decipher what information or records CFI is actually required to report or maintain pursuant to these conditions, and LDEQ must revise the permit to clarify precisely which *specific* reporting requirements that it is incorporating from Subpart DDDDD.

As a general matter, Commenters agree that CEMS is an appropriate method of measuring continuous NOx emissions and could be used to demonstrate compliance with the NOx limits. However, CEMS is only effective if it is functioning properly, and it is not clear from the permit whether there are any explicit requirements to periodically calibrate or perform an audit of the CEMS. LDEQ should clarify whether there are any specific requirements to periodically calibrate or perform an audit of the CEMS, and if there are none, should revise the permit to include such requirements.

While Condition 34 requires CFI to perform a periodic performance test at each heater, Condition 35 indicates that this test is solely for the purpose of determining CO emissions. Thus, the permit appears to contain no testing, monitoring, or reporting requirements specific for the hourly emission limits for PM10, PM2.5, VOCs, or any of the TAPs (ammonia, formaldehyde, n-hexane, or zinc and compounds). Relatedly, though Condition 29 establishes annual emission limits for each of these pollutants that are to apply during the 1-year commissioning period, neither Condition 29 nor any other conditions actually impose any monitoring or testing requirements to demonstrate compliance with those limits. LDEQ must revise the permit to include testing, monitoring, and reporting requirements for the hourly emission limits for PM10, PM2.5, VOCs, and TAPs, along with a clear explanation for why these requirements are sufficient to assure compliance with those hourly limits. LDEQ must also revise the permit to include testing, monitoring, and reporting requirements sufficient to assure compliance with the annual limits applicable during the commissioning period under Condition 29.

Further, Condition 34 only requires CFI to conduct a performance test for CO emissions at each heater once every five years, "plus or minus 6 months." As a Title V permit must be renewed every five years, this condition appears to allow for the possibility that CFI may not even be required to test each heater once each permit term—which is plainly impermissible. A requirement to test each heater just once every five years *at most*, with no continuous or parametric monitoring to assure compliance during the periods of operation in-between performance tests, is plainly insufficient to assure compliance with these heaters' CO limits, which are hourly limits that apply at all times of operation. While Condition 32 also establishes a CO BACT limit of 0.083 lb/mmBtu that is purportedly calculated on a 30-day rolling average basis, it does not actually require any testing for CO emissions, or parametric monitoring, beyond the once-per-five-year performance test, leaving it entirely unclear *how* CFI is to calculate CO emissions on a 30-dayrolling average basis. Instead, it merely states that CFI will control emissions through "good combustion practices."

EPA has frequently found that even annual stack testing by itself, without any sort of parametric monitoring, is insufficient to assure compliance with an hourly limit. *See, e.g., In re*

Northeast Maryland Waste Disposal Authority, Order on Petition No. III-2019-2 (Dec. 11, 2020) ("NMWDA Order") at 9. In the NMWDA Order, EPA specifically found that annual stack testing by itself was insufficient to assure compliance with an hourly limit for hydrochloric acid at Covanta's incinerator in Montgomery County, Maryland. *Id.* Further, EPA's order suggested that even monitoring on a 3-hour block basis is likely inadequate to assure continuous compliance with an hourly standard. *Id*. at 10-11; note 10 ("use of a 3-hour block average, even if using a certified HCl CEMS, is likely inappropriate for demonstrating compliance with a 1-hour standard."). EPA has repeatedly directed permitting authorities to consider a multi-pronged monitoring approach of periodic stack testing accompanied by other clearly identified permit terms such as parametric monitoring. *In the Matter of Oak Grove Management Company, Oak Grove Steam Electric Station,* Order on Petition No. VI-20 17-12 at 25-26 (October 15, 2021) (objecting to permit which did not provide for any other monitoring that could be used, in conjunction with annual stack testing, to adequately assure continuous compliance with hourly emission limits for H2SO4, HCl, HF, VOC, and total PM/PM10).

LDEQ should require the use of a CO continuous emission monitoring system ("CEMS") to assure compliance with the hourly CO limits at these units. In the event that LDEQ does not require CEMS, then at a bare minimum, LDEQ must require stack testing on an at least annual basis, and include continuous or parametric monitoring requirements to assure compliance during the periods of operation in-between performance tests. For each parameter chosen, LDEQ must also clearly explain how that parameter is related to CO emissions, and why the parametric levels selected will ensure continuous compliance with the heaters' hourly CO emission limits.

c. *Natural Gas Fired Engines – Standby Generators 1 & 2 (EQT 12, 13)*

i. Applicable emission limits

The Emission Rate tables list the following "emission rates" for criteria pollutants and TAPs/HAPs for Standby Generators 1 and 2. (The emission rates listed are identical for both units).

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	41
PM10	0.20	0.20	0.01
PM2.5	0.20	0.20	0.01
SO2	-	-	-
NOx	8.20	8.20	0.41
CO	4.20	4.20	0.21
VOC	1.40	1.40	0.07
Ammonia	-	-	41
Acetaldehyde	0.02	0.02	<0.01
Acrolein	0.02	0.02	0.001
Benzene	0.01	0.01	<0.01
Formaldehyde	0.20	0.20	0.01
Methanol	0.02	0.02	<0.01

Draft Permit Package at 26, 30.

Additionally, Conditions 37 through 39 incorporate specific limits from 40 CFR 60 Subpart JJJJ of: 1.0 g/brake-horsepower-hour ("BHP-hr") for VOCs (excluding formaldehyde); 4.0 g/BHP-hr for CO; and 2.0 g/BHP-hr for NOx, respectively.

Condition 51 also establishes an opacity limit of 20%, which it states will be complied with by using sweet natural gas as fuel.

ii. Monitoring and testing requirements

The Draft Title V Permit does not appear to contain any testing or monitoring requirements for any of the limits described above.

Condition 47 generally requires CFI to keep records of "equipment/operational data," but does not specify what this entails. Condition 47 also states that CFI shall keep "records of the information in 40 CFR 60.4245(a)(1) through (a)(4)," which encompasses notifications submitted to comply with Subpart JJJJ, records of maintenance, and either documentation from the manufacturer that the engine is certified to meet the emission standards in other subparts (if certified), or other documentation that the engine meets emission standards if it is not certified.

Condition 53 states a requirement to "[c]alibrate elapsed run-time and fuel meters, oxygen, diluents, and CO monitors, and other such instrumentation required by LAC 33:III.2201 according to the manufacturer's recommendations, but not less frequently than once per year." None of the other requirements related to these units reference any of these pieces of equipment (such as the CO monitors), so it is unclear what instrumentation is actually on these units.''

Condition 56 states that BACT for NOx, CO, and CO2e from these units is "certified engines, good combustion practices, and compliance with NSPS 40 CFR 60 Subpart JJJJ."

iii. Adequacy of requirements

Conditions 37 through 39 incorporate g/BHP-hr limits for VOCs, CO, and NOx from 40 CFR 60 Subpart JJJJ, but do not appear to include any testing, monitoring, or reporting requirements to demonstrate compliance with these limits. Though it is not clear from the face of Condition 41 itself, our understanding from a review of Subpart JJJJ is that engines that are properly certified under Subpart JJJJ are certified by the manufacturer to meet the emission limits of Subpart JJJJ, and that performance testing is not required for certified engines. 40 C.F.R. 60.4243(a)(1). Assuming this is correct, LDEQ should revise Condition 41 to make it clear that certification is the compliance method for the limits in Condition 37-39. If this is not correct, LDEQ must revise the permit to include additional testing, monitoring, or reporting requirements to demonstrate compliance with these limits.

The Emission Rates tables for criteria pollutants and TAPs establish average hourly, maximum hourly, and tpy limits for PM10, PM2.5, NOx, CO, VOC, acetaldehyde, acrolein, benzene, formaldehyde, and methanol. However, none of the specific requirements applicable to

these units appear to include any testing, monitoring, or reporting requirements to demonstrate compliance with these limits *at all*. LDEQ must revise the permit to include testing, monitoring, and reporting requirements attached to these hourly and annual emission limits, along with a clear explanation for why these requirements are sufficient to assure compliance with those limits. Alternatively, LDEQ must clearly explain in the permit record its rationale for failing to include testing and monitoring requirements.

Finally, Condition 51 establishes an opacity limit of 20%, which it states will be complied with by using sweet natural gas as fuel. Opacity is typically measured through a visual inspection, and it is unclear to us how using sweet natural gas could assure compliance with an opacity limit—and nothing in the permit record explains the connection between sweet natural gas and opacity. LDEQ must either clearly explain its rationale in the permit record for why it believes the use of sweet natural gas by itself can assure compliance with the opacity limit, or revise the permit to include additional testing and monitoring requirements to demonstrate compliance with the opacity limit at these engines.

d. *Ammonia Storage Tank Flares A & B (EQT 6, 7)*

i. Applicable emission limits

The Emission Rate tables list the following "emission rates" for criteria pollutants and TAPs/HAPs for the Ammonia Storage Tank Flares. With the exception of ammonia, the emission rates listed are identical for both units.

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	1055
PM10	-	-	-
PM2.5	-	-	-
SO2	-	-	-
NOx	2.17	47.67	9.51
CO	1.13	22.30	4.95
VOC	0.01	0.22	0.05
Ammonia (EQT 6)	127.86	159.83	31.65
Ammonia (EQT 7)	7.23	159.83	31.65
Formaldehyde	0.002	0.003	<0.01

Draft Permit Package at 25-30.

Condition 75 establishes an opacity limit of 20%, except for a combined total of six hours over any 10 consecutive day period, for "burning in connection with pressure valve releases for control over process upsets." Condition 77 also establishes an (apparently parallel/overlapping) opacity limit of 20%, except for one six-minute period in any 60 consecutive minutes.

ii. Monitoring and testing requirements

Condition 75 states that opacity will be determined either though visual inspections using EPA Method 9 of 40 CFR Part 60, Appendix A, or by using a continuous opacity monitoring system ("COMS"). Condition 79 states that CFI will ensure compliance with the opacity limits through daily Method 9 visual inspections.

Condition 82 states that CFI shall continuously monitor and record the volume of vent gas routed to the flare. Conditions 80-81 generally require monitoring and recordkeeping for the presence of a flame.

Condition 83 states that BACT for NOx, CO, and CO2e emissions is determined to be a combination of proper design and operation and good combustion practices, including establishment of flare minimization practices.

iii. Adequacy of requirements

Aside from the visual opacity inspections and general requirement to monitor flame presence, the Draft Title V Permit apparently contains no testing or monitoring requirements at all for emissions from these flares. As with the Syngas and Ammonia Gas Flare above, the permit does *not* include any limits, testing, or monitoring requirements related to a number of typical indicators of flare performance, such as destruction efficiency ("DRE"), net heating value, or inlet gas content. If it is LDEQ's position that the current conditions are sufficient to assure compliance with each of the hourly and annual limits for these flares, LDEQ must at a minimum explain clearly in the permit record how these conditions relate to the emission limits and why it believes they are adequate to assure continuous compliance with the limits. Adequate testing and monitoring requirements are especially important here, because these units account for a very significant portion of the Facility's projected ammonia emissions.

e. *Standby Generators 3, 4, and 5 (EQT 19, 20, 24)*

i. Applicable emission limits

The Emission Rate tables list the following "emission rates" for criteria pollutants and TAPs/HAPs for Standby Generators 3-5. The emission rates listed are identical for all three units.

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	141
PM10	4.00	4.00	0.20
PM2.5	4.00	4.00	0.20
SO2	0.03	0.03	<0.01
NOx	54.80	54.80	2.74
CO	4.60	4.60	0.23
VOC	3.60	3.60	0.18
Benzene	0.01	0.01	<0.01

Condition 85 requires CFI to comply "with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power." Condition 86 requires CFI to "achieve the emission standards as required in 40 CFR 60.4204 and 40 CFR 60.4205" over the entire life of the engines. Finally, Condition 91 states that these units must "meet the requirements of 40 CFR 1068, as applicable." However, as previously discussed because none of these conditions state the specific standards that apply to these units and simply provide high-level citations to provisions containing many different potential requirements that only apply to emission units meeting certain criteria, it is not actually clear what the specific emission limits and standards are from these provisions that apply to these units.

Conditions 100 and 101 both establish an opacity limit of 20%, except for one six-minute period in any 60 consecutive minutes.

ii. Monitoring and testing requirements

Condition 87 requires the use of diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel. Condition 88 requires CFI to monitor operating time continuously during operation. Condition 94 generally limits hours of operation for maintenance checks and readiness testing to a maximum of 100 hours per calendar year, while Condition 95 imposes a limit of no more than 50 hours per calendar year for non-emergency situations. Condition 93 states that there is no time limit on the use of these emergency generators in emergency situations. Condition 97 requires CFI to record all operating time for the generators, and the reason the engine was in operation during that time.

Conditions 89, 90, and 92 require CFI to ensure that each engine is certified to the applicable emission standards in Subpart IIII and is installed and configured according to the manufacturer's emissions-related specifications, and requires CFI to operate and maintain the engines according to the manufacturer's emission-related written instructions and change only those emission-related settings that are permitted by the manufacturer. Condition 102 states that BACT for NOx, CO, and CO2e emissions from the standby generator engines is determined to be "certified engines, good combustion practices, and compliance with NSPS 40 CFR 60 Subpart IIII."

Finally, Condition 100 states that opacity shall be determined using either EPA Method 9 inspections, or by using a COMS.

iii. Adequacy of requirements

Our understanding is that performance testing is not required for engines that are properly certified by the manufacturer to meet the emission limits of Subpart IIII, and operated in accordance with those manufacturer instructions, because certification is generally considered sufficient to demonstrate compliance with the limits in Subpart IIII. 40 C.F.R. 60.4211(b)(1). Assuming this is correct, LDEQ should revise Conditions 85 and 86 to make it clear (1) precisely what emission standards and limitations are actually applicable to these units, and (2) whether certification is the compliance demonstration method for said limits and standards, and if so,

which specific limits. If this is not correct, LDEQ must revise the permit to include additional testing, monitoring, or reporting requirements to demonstrate compliance with these limits.

LDEQ should also clarify the origins of the hourly and annual emission limits for CO2e, PM10/2.5, SO2, NOx, CO, VOC, and benzene contained in the Emission Rate table, and specifically clarify whether these emission limits are the same limits that are incorporated from Subpart IIII. If they are **not** the same as the limits required by Subpart IIII, LDEQ must revise the permit to include testing, monitoring, and reporting requirements attached to these hourly and annual emission limits, along with a clear explanation for why these requirements are sufficient to assure compliance with those limits, as the specific requirements applicable to these units do not contain any testing or monitoring provisions aside from certification and "good combustion practices." Condition 102. We also note that Condition 102 only states that certification and good combustion practices are BACT for NOx, CO, and CO2e emissions, and that none of the specific requirements address PM, SO2, or benzene emissions.

f. *Auxiliary Boiler (EQT 11)*

i. Applicable emission limits

The Emission Rate tables list the following "emission rates" for criteria pollutants and TAPs/HAPs from the Auxiliary Boiler:

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	132,087
PM10	3.38	4.22	7.39
PM2.5	3.38	4.22	7.39
SO2	0.27	0.33	0.58
NOx	4.46	6.18	19.51
CO	37.31	46.63	81.70
VOC	2.44	3.05	5.35
Ammonia	1.83	5.09	8.03

The TAPs/HAPs Emission Rate table also includes average hourly, maximum hourly, and annual tpy limits for 1,4-Dichlorobenzene, ammonia, barium (and compounds), benzene, cadmium (and compounds), chromium VI (and compounds), copper (and compounds), formaldehyde, n-Hexane, naphthalene (and methyl naphthalenes), nickel (and compounds), toluene, and zinc (and compounds).

Condition 103 establishes a NOx limit of 0.10 lb/mmBtu, while Condition 137 establishes a Nox BACT limit of 9 ppmvd @ 3% O2, which the permit indicates is stricter than the limit in Condition 103.

Condition 133 limits total suspended particulate to no more than 0.6 lb/mmBtu, which Condition 133 states will be complied with by using sweet natural gas as fuel.

Condition 134 establishes annual emission limits for the commissioning period, which appear identical to the annual emission rates listed in the tables—but does not require any monitoring or testing, and does not explain how compliance with these annual limits will be measured or demonstrated.

ii. Monitoring and testing requirements

Conditions 105 – 109 require CFI to install and operate continuous monitoring systems ("CMS") to continuously measure NOx, oxygen, and carbon dioxide emissions.

Condition 110 states that the 1-hour average NOx emission rates measured by the required continuous NOx monitor shall be expressed in ng/J or lb/MMBtu heat input and used to calculate the average emission rates for purposes of compliance with the NOx limits. Condition 116 requires CFI to maintain records of certain info listed in 40 CFR 60.49b(g)(l) through (g)(l0), which appears to request the information typically included in a standard periodic compliance report (e.g., date, average hourly NOx rate, 30-day NOx rate, days where the 30-day rate was over emission standards, reasons for the emissions and corrective actions taken, etc.).

Condition 115 requires CFI to record amounts and types of fuels combusted and calculate annual capacity factors for each fuel on a 12-month rolling average basis. Condition 128 requires CFI to submit semi-annual deviation/compliance status reports. Condition 129 generally requires CFI to keep records of "equipment/operational data" but does not specify what this entails. Condition 129 also states that CFI shall keep "records of the information in 40 CFR 63.7555(a) through (h), as applicable"—but because this is a high-level general citation to Subpart DDDDD, it is unclear precisely what actual records CFI is required to maintain.

Condition 121 requires CFI to conduct a tune-up of the auxiliary boiler once every five years.

Finally, Condition 135 states that BACT for CO2e is a combination of "low carbon fuel, energy efficient design, and good combustion, operating, and maintenance practices." Condition 136 states BACT for CO emissions is "good combustion practices." Condition 137 states BACT for NOx emissions is the combination of low-NOx burners and SCR.

iii. Adequacy of requirements

LDEQ should clarify how the use of sweet natural gas as fuel is sufficient to assure compliance with Condition 133's total suspended particulate limit of 0.6 lb/mmBtu.

Commenters generally agree that CEMS is an appropriate method of measuring continuous NOx emissions and could be used to demonstrate compliance with the NOx limits. As noted previously, LDEQ should clarify whether there are any specific requirements to periodically calibrate or perform an audit of the CEMS, and if there are none, should revise the permit to include such requirements.

The Draft Title V Permit does not appear to have any testing or monitoring requirements to demonstrate or assure compliance with all of the other hourly and tpy limits applicable to the Auxiliary Boiler, including the limits for PM10, PM2.5, SO2, CO, VOC, ammonia, and the extensive list of TAPs identified above. While the permit does contain a requirement to perform a tune-up every 5 years, and a requirement to record amounts and types of fuels combusted, nothing in the permit indicates that these requirements are actually related to demonstrating compliance with any of the applicable hourly or annual emission limits. And even if they were, they would certainly not be sufficient on their own to demonstrate compliance with either the short-term or long-term limits, without a clear explanation from LDEQ as to how they relate to and can assure compliance with the limits.

LDEQ must revise the permit to include testing, monitoring, and reporting requirements attached to these hourly and annual emission limits—including for the annual emission limits that apply during the commissioning period per Condition 134—along with a clear explanation for why these requirements are sufficient to assure compliance with those limits. Ensuring that this unit has adequate testing and monitoring requirements, and enforceable emission limits, is especially important because it comprises a significant portion of the permitted CO and PM10/2.5 emissions from this Facility. Further, as discussed previously, unless the average hourly emission rate is a clearly enforceable emission limit, the actual PTE for PM10/2.5 from this unit is substantially over the estimated 7.39 tpy, pushing this Facility over the major PSD threshold for PM10/2.5.

g. *Ammonia Synthesis Loop Startup Heater (EQT 29)*

i. Applicable emission limits

The Emission Rate tables list the following "emission rates" for criteria pollutants from the Ammonia Synthesis Loop Startup Heater:

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	846
PM10	0.19	0.23	0.05
PM2.5	0.19	0.23	0.05
SO2	-	-	-
NOx	1.26	1.51	0.31
CO	2.12	2.54	0.52
VOC	0.14	0.17	0.03

Condition 140 requires CFI to be in compliance with "all applicable emission limits, work practice standards, and operating limits" in Subpart DDDDD—but because this is an improper incorporation by reference, it is impossible to tell from the permit what these applicable requirements are.

Condition 153 states a CO BACT emission limit of 0.083 lb/mmBtu on a 7-day rolling average basis. Condition 154 states a NOx BACT emission limit of 0.05 lb/mmBtu on a 7-day rolling average basis.

The heater is also subject to a requirement limiting total suspended particulate to no more than 0.6 lb/mmBtu, which Condition 146 states will be complied with by using sweet natural gas as fuel.

Condition 147 establishes annual emission limits that are to apply during the 1-year commissioning period, which appear to be identical to the annual tpy emission rates listed in the Emission Rate tables.

ii. Monitoring and testing requirements

Condition 138 requires CFI to conduct a tune-up once every five years. Condition 142 requires CFI to keep records of "the information specified in 40 CFR 63.7555(a) through (h), as applicable." Because 40 CFR 63.7555(a) through (h) lists a wide range of information that a permittee may be required to submit depending on certain criteria and the Draft Title V Permit does not specify which specific requirements apply, it is unclear what precise information CFI is required to maintain records of under these conditions.

Condition 148 limits operating time to no more than 495 hour/year, and Conditions 149-151 require CFI to monitor,[119] record, and submit an annual report of total operating hours. The permit does not contain any additional monitoring or testing requirements for this heater.

Finally, Condition 152 states that BACT for CO2e is a combination of "low carbon fuel, energy efficient design, and good combustion, operating, and maintenance practices." Condition 153 states BACT for CO emissions is "good combustion practices." Condition 154 states BACT for NOx emissions is low-NOx burners.

iii. Adequacy of requirements

The Draft Title V Permit does not appear to contain any associated testing or monitoring requirements for any of the hourly or tpy emission limits listed in the emission rate table above, for the annual limits that apply during the commissioning period, or for the CO and NOx lb/mmBtu BACT limits in Conditions 153 and 154. Nothing in the permit explains how compliance will be measured or demonstrated with any of these limits.

To the extent that LDEQ is simply relying on "good combustion practices" and the low-NOx burners, LDEQ must still clearly explain how these are sufficient to assure compliance with the BACT limits for CO and NOx. As explained above, the mere fact that an emission limit is

[119] Condition 149 states: "Operating time monitored by technically sound method upon occurrence of event." Commenters note that it is not entirely clear what a "technically sound method" entails. The only citation Condition 149 provides is LAC 33:III.501.C.6, which generally requires LDEQ to incorporate sufficient terms and conditions to ensure compliance with all state and federally applicable requirements.

low does not "mean that compliance with such limit can be assured with less testing or without monitoring." Neville Order at 14

LDEQ must revise the permit to include testing, monitoring, and reporting requirements attached to all of the hourly and annual emission limits described above—including for the annual emission limits that apply during the commissioning period per Condition 147—along with a clear explanation for why these requirements are sufficient to assure compliance with those limits.

h. *CO2 Vent (VNT-CO2)*

The Emission Rate tables list the following "emission rates" for the CO2 Vent:

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	289,272
CO	6.12	6.12	2.95
VOC	59.36	80.32	28.60
Methanol	56.30	76.50	27.13

As discussed already at length in Section 1.A, the permit contains no monitoring or testing requirements at all for any of these limits, and the only method of compliance with these limits—an assumed 89% CCS rate—is never mentioned at all in the permit, let alone a requirement of the permit. As explained, this is clearly impermissible, and none of these emission limits are enforceable as either a legal or practical matter.

i. *Steam Superheater, Fired Process Heater, and Auxiliary Boiler "Start-up" (22B001 SU, 13B001 SU, and 23U510 SU)*

As touched on briefly in Section II.C and II.C.1 of these comments, the Draft Title V Permit appears to establish separate hourly and annual limits that apply to the Steam Superheater, the Fired Process Heater, and the Auxiliary Boiler during periods of "start-up." These include the following limits listed in the "Emission Rates" table, Draft Permit Package at 27-28:

Steam Superheater (EQT 5), 22B0001 (SU)

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
PM10	-	3.23	-
PM2.5	-	3.23	-
SO2	-	0.26	-
NOx	-	59.56	-
CO	-	35.73	-
VOC	-	2.34	-

Fired Process Heater (EQT 28), 13B001 (SU)

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
PM10	-	2.65	-
PM2.5	-	2.65	-
SO2	-	0.21	-
NOx	-	48.73	-
CO	-	29.24	-
VOC	-	1.91	-

Auxiliary Boiler (EQT 11), 23U510 (SU)

Pollutant	Average hourly (lb/hr)	Max hourly (lb/hr)	Annual (tpy)
CO2e	-	-	2,170
PM10	3.38	4.22	0.12
PM2.5	3.38	4.22	0.12
SO2	0.27	0.33	0.01
NOx	62.81	77.72	2.24
CO	37.31	46.63	1.34
VOC	2.44	3.05	0.09

Draft Title V Permit Conditions 160-166 also establish the same BACT emission limits of 0.083 lb/mmBtu for CO and 0.14 lb/mmBtu for NOx for each of these units (SU). However, these specific requirements do not contain any monitoring or testing provisions or otherwise specify how compliance with the separate emission limits that apply during periods of startup will be determined. As discussed above, it appears all of these units are required to be equipped with CEMS for NOx, so Commenters presume that these CEMS will be used to comply with the NOx BACT limit during start-up. However, this should be clarified explicitly.

Further, it is not clear how CFI will assure compliance with any of the emission limits for non-NOx pollutants applicable to these units during periods of startup. For example, as discussed above, the Auxiliary Boiler does not have any testing or monitoring requirements to demonstrate or assure compliance with any of its other hourly and tpy limits, including the limits for PM10, PM2.5, SO2, CO, VOC, ammonia, and multiple other TAPs. The two CRG 2 Heaters similarly do not have any testing or monitoring requirements for PM10, PM2.5, SO2, or VOCs. While Conditions 34 and 35 do require performance tests for CO emissions, this is only required once every five years (plus or minus 6 months), and it is unclear how this performance testing requirement will apply for emissions during periods of startup. The Draft Title V Permit also does not define startup or otherwise explain when these limits will apply.[120]

LDEQ must revise the permit to include testing, monitoring, and reporting requirements attached to all of the hourly and annual emission limits described above, along with a clear

[120] As noted in Section II.C, though the "annual" tpy emission rates for the Auxiliary Boiler appear to have been calculated based on an assumed, very limited operating hours/year, there is no actual requirement in the Draft Title V Permit that actually limits hours of operation.

explanation for why these requirements are sufficient to assure compliance with those limits. LDEQ must also revise the permit to include enforceable limits on hours of operation for startup, as well as actually define what "startup" entails.

j. *Fugitive Emissions (FUG1)*

Finally, the Emission Rate table states an average hourly emission rate of 3.56 lb/hour and an annual emission rate of 15.48 tpy for ammonia emissions attributable to fugitive emissions.

The only monitoring for fugitives is a requirement to perform "audio, olfactory, and visual checks for ammonia leaks within the operating and storage areas" to be made daily. Condition 155. This is not sufficient because audio, olfactory, and visual checks are unreliable and unlikely, on their own, to enable CFI to accurately and reliably detect such leaks. For example, olfactory inspections for ammonia, which has a strong, pungent smell, sounds feasible on paper—but it is likely to be unreliable at an ammonia plant since, as the CDC's National Institute for Occupational Safety and Health notes, persons with prolonged exposure to ammonia lose their ability to detect the odor due to olfactory fatigue (colloquially known as "smell blindness").[121] Similarly, while ammonia can form a visible cloud once it reacts with other particles in the air, in its pure form ammonia gas is colorless—making visual inspections similarly unreliable.

Additional forms of reliable monitoring for fugitives is especially important here because, as discussed in prior sections of these comments, Dr. Pless and Dr. Battye have both determined that CFI has likely significantly underestimated the amount of fugitive ammonia emissions from this Facility—and as Dr. Battye's modeling shows, the Facility's modeled ammonia impacts likely exceed Louisiana's ambient air standard for ammonia. Battye Ammonia Report at 2–5; Pless Report at 26-39.

LDEQ should require CFI to implement a fenceline monitoring program for ammonia vapor at this Facility. Fenceline monitoring for ammonia is not only feasible, but has been regularly used effectively by many different types of industrial sites—including ammonia plants—for decades. For example, numerous refineries in California operate monitoring systems that measure real-time concentrations of several pollutants, including VOCs and ammonia.[122]

---

[121] Emergency Response Safety and Health Database. Ammonia Solution, Ammonia, Anhydrous: Lung Damaging Agent. https://www.cdc.gov/niosh/ershdb/emergencyresponsecard_29750013.html

[122] *See, e.g.*, Chevron Richmond Refinery air monitoring measurements, available at https://www.richmondairmonitoring.org/measurements.html;
Phillips 66 Rodeo Refinery Fenceline Monitoring, available at https://www.rodeofencelinemonitoring.com/;
Chevron El Segundo, available at https://elsegundo1180.com/data.html;
Marathon Los Angeles Refinery Fenceline Air Monitors, available at https://marathonlosangelesrefineryfencelinemonitoring.com/monitors.html;
Phillips 66 Carson Refinery Fenceline Air Monitors, available at https://www.p66losangeles1180.com/data.html?page=1;

EPA has recently required the use of fenceline monitoring to detect ammonia at other ammonia plants, such as Dyno Nobel, Inc.'s ammonia facility in St. Helens, Oregon.[123] There is no reason LDEQ should not require CFI to use fenceline monitoring here as well.

III. LDEQ Has Not and Cannot Satisfy Its Public Trustee Duty Under Article IX, Section 1 of the Louisiana Constitution Based on the Current Record.

Article IX, Section 1 of the Louisiana Constitution establishes a public trustee duty for all agencies of the State, and mandates that:

> The natural resources of the state, including air and water, and the healthful, scenic, historic, and esthetic quality of the environment shall be protected, conserved, and replenished insofar as possible and consistent with the health, safety, and welfare of the people.

The Supreme Court of Louisiana has held that this provision creates a constitutional duty on the part of LDEQ to ensure that "before granting approval of any proposed action affecting the environment… that adverse environmental impacts have been minimized or avoided as much as possible consistently with the public welfare." *Save Ourselves v. La. Envt'l. Control Comm'n,* 452 So. 2d 1152, 1157 (La. 1984). Though LDEQ retains a degree of discretion in determining how to balance various competing public interests, the Court has emphasized that the agency is "duty bound to demonstrate that it has properly exercised the discretion vested in it by the constitution and the statute," and must clearly explain the reasons for its decision and its factual findings in the record. *Id.* at 1160; *see also In re: Matter of Am. Waste & Pollution Control Co.,* 642 So. 2d 1258, 1266 (La. 1994) ("Only by detailing its reasoning does the DEQ uphold its position as public trustee and justify the discretion with which it is entrusted by constitutional and statutory authority in a contested environmental matter.") (citing *Save Ourselves*, 452 So. 2d at 1160).

The Supreme Court of Louisiana has further noted that this constitutional duty is *not* satisfied by mere adherence to LDEQ's *own* regulations but requires LDEQ to affirmatively demonstrate that it has adequately "performed its duty to see that the environment would be protected to the fullest extent possible consistent with the health, safety and welfare of the people." *Save Ourselves*, 452 So. 2d at 1160 (stating regardless of whether agency adhered to its own regulations, the administrative record did not demonstrate that the agency had fulfilled its public trustee duty, and noting that "the agency may have erred by assuming that its duty was to adhere only to its own regulations rather than to the constitutional and statutory mandates."); *see also In re: Matter of Am. Waste & Pollution Control Co.,* 642 So. 2d at 1265-6 (stating that a court "must reverse" an agency's decision "if the decision was reached 'without individualized

---

Phillips 66 Wilmington Refinery Fenceline Air Monitors, available at https://www.p66losangeles1180.com/data.html?page=2.

[123] *See* Consent Decree, 3:19-cv-00984, U.S. District of Oregon (June 24, 2019), Appendix D (page 87 of PDF). Available at: https://www.epa.gov/sites/default/files/2019-06/documents/dynonobel-cd.pdf

consideration and balancing of environmental factors conducted fairly and in good faith.'").

The First Circuit has further clarified that *Save Ourselves* articulates five specific factors, commonly referred to as the "IT factors,"[124] that must be addressed by LDEQ in order to show that it has satisfied its public trustee duty. Specifically:

1. Have the potential and real adverse environmental effects of the proposed facility been avoided to the maximum extent possible?
2. Does a cost benefit analysis of the environmental impact costs balanced against the social and economic benefits of the proposed facility demonstrate that the latter outweighs the former?
3. Are there alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits?
4. Are there alternative sites which would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits?
5. Are there mitigating measures which would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits?

In re: Matter of Am. Waste & Pollution Control Co., 633 So. 2d 188, 194 (La. Ct. App. 1993).[125]

Because LDEQ has an affirmative duty to demonstrate through the administrative record that it has fulfilled its public trustee duty, a reviewing court will examine whether LDEQ has adequately demonstrated that it has satisfied each factor regardless of whether it is challenged. *Rise St. James v. Louisiana Dep't of Env't Quality*, 2023-0578 (La. App. 1 Cir. 1/19/24), 383 So. 3d 956, 982, *reh'g denied* (Feb. 15, 2024)[126] (reviewing LDEQ's analysis of alternative projects despite expressly acknowledging that it had not actually been challenged by plaintiffs, because "this issue must be addressed by DEQ in a complete and thorough analysis of the IT issues.").

LDEQ cannot demonstrate that it has met its public trustee duty here, because (1) the permit record shows that LDEQ relied entirely on CFI's own inadequate Environmental Assessment Statement ("ESA") and that LDEQ has not independently evaluated the information CFI provided; (2) CFI's ESA and application failed to provide the critical information necessary to evaluate these factors; and (3) as discussed above, the proposed permits are severely deficient and do not comply with the requirements of the Clean Air Act.

[124] *Save Ourselves* is widely referred to as the "IT" decision because it revolved around a facility proposed by the IT Corporation.
[125] *writ granted,* 634 So. 2d 837 (La. 1994), and *aff'd and remanded,* 93-3163 (La. 9/15/94), 642 So. 2d 1258.
[126] *writ denied*, 2024-00354 (La. 9/4/24), 391 So. 3d 1051, and *writ denied*, 2024-00355 (La. 9/4/24), 391 So. 3d 1052, and *writ denied*, 2024-00351 (La. 9/4/24), 391 So. 3d 1060.

A. The permit record does not show that LDEQ has independently evaluated any of the information CFI provided.

As an initial matter, Commenters note that nothing in the administrative record demonstrates that LDEQ has performed an independent evaluation of the five IT factors. Instead, it appears that the only evaluation of the IT factors in the permit record is CFI's own ESA. Further, there is no evidence in the record that LDEQ independently evaluated *any* of the information that CFI provided in its EAS. In fact, neither the permits nor LDEQ's Statement of Basis accompanying the permits ever references the EAS or any of the information provided in the EAS. In fact, the only reference to the EAS in the entire permit record appears to be a single sentence in the public notice, which states that "[t]he EAS submitted by the applicant addresses avoidance of potential and real environmental effects, balancing of social and economic benefits against environmental impact costs, and alternative sites, projects, and mitigative measures." Draft Permit Package at 2.

As the Supreme Court of Louisiana has noted, LDEQ retains a degree of discretion in determining how to balance various competing public interests under its public trustee duty—however, the point of "very important procedural provisions" established by Louisiana's constitutional and statutory requirements is to ensure "that the discretion entrusted to the [LDEQ] is in fact exercised in each individual case." *Save Ourselves*, 452 So. 2d at 1157. LDEQ bears the public trustee duty, and it is LDEQ's burden—*not* the applicant's—to affirmatively demonstrate that it has "performed its duty to see that the environment would be protected to the fullest extent possible consistent with the health, safety and welfare of the people." *Id.* at 1160. LDEQ cannot satisfy its constitutional obligation by simply rubberstamping CFI's own EAS and incorporating it by reference—it must clearly articulate the reasons for its decision, as well as its factual findings, in the administrative record. *Id.* at 1161 (remanding decision back to agency because the record was silent as to the reasons for the agency's decisions, and court could ultimately not discern what the agency's decision-making process was).

LDEQ cannot reasonably claim that it has discharged its public trustee duty when nothing in the record actually indicates that LDEQ performed its own evaluation of the IT factors, or meaningfully evaluated any of the information provided by CFI's EAS. It is especially clear that LDEQ cannot satisfy its burden here because CFI's EAS is woefully deficient and fails to provide even the basic information necessary to evaluate the IT factors.

B. LDEQ must require CFI to provide additional information necessary to evaluate each of the IT factors.

CFI's EAS submitted with its revised application purports to provide the information necessary for LDEQ to assess the five IT factors under its public trustee duty. However, the information provided by this EAS is so lacking that it is difficult to see how LDEQ can assess some of the IT factors at all on the basis of this information, let alone adequately.

CFI's EAS often reads more like an advert than a serious environmental assessment. It is thick with corporate buzzwords yet light on the substantive information that matters to this

permitting action. There are many instances where CFI's EAS falls significantly short of providing the information necessary for a proper evaluation of the IT factors. LDEQ cannot adequately discharge its constitutional public trust duty without this information, and it is LDEQ's obligation to ensure that CFI provides this information.

1. The EAS does not include information to support CFI's claims about the purported benefits of the project related to CCS.

For example, though CFI spends an extensive amount of time touting the purported benefits of CCS and its corporate commitment to decarbonization, it never provides even the most basic details about the *mechanics* of the proposed CCS upon which this entire project relies—such as who will be accepting the carbon generated by the Facility, where the carbon will be sent for sequestration, where the pipelines to transport this carbon will be located, how many miles of pipeline will be needed, or (most crucially), ***any*** information that would support its advertised CCS capture efficiency. These omissions are particularly troubling because much of the analysis in the EAS is predicated on the high availability of CCS. For example, CFI's EAS explicitly states that at least one of the reasons that this particular site was chosen—and that CFI determined alternative sites would not do—is the availability of CO2 pipelines and CCS facilities in this area. Draft Permit Package at 486. Further, CFI relies in large part on its assumed CCS in its analysis of factor two (environmental impact costs balanced against the social and economic benefits), which states that "capturing the CO2 from the process causes low carbon ammonia to be favorable from an Environmental Impact Cost standpoint." *Id*. at 467.

In spite of the clear importance of CCS to CFI's statements that the benefits of the proposed Facility's construction and operation outweigh the adverse environmental impacts, CFI provides no actual details about its planned CCS and merely vaguely states that "[s]everal options for carbon capture and sequestration are available for development or partnership." Draft Permit Package at 488. As noted previously, a review of online press releases and CFI's SEC filings[127] indicates that CFI has entered into a contract with 1PointFive to sequester this Facility's CO2 stream at 1PointFive's proposed Pelican Sequestration Hub—a facility which has not yet even begun construction. This detail is, of course, incredibly relevant to this analysis. The terms of the contract in question, and any assurances 1PointFive has provided (or has *not* provided) regarding CCS capacity and timeline, would also seem to be highly relevant information. A realistic estimate of CCS capture rates is especially pertinent information for evaluating the IT factors because, as CFI's permit application (and VOC calculation) makes clear, any emissions that are not captured through CCS will be vented **directly** to the atmosphere via the CO2 Vent. Thus, even a relatively small variation in CCS rates will have significant impacts on the calculus surrounding expected environmental impact costs, adverse environmental effects, and appropriate mitigations. And yet, the EAS never actually provides any estimate for CCS capture rate, and neither of the proposed permits include any requirement for CFI to capture any carbon emissions at all, let alone achieve a specific minimum CCS rate.

These critical details that should have been included in the EAS to support CFI's claims about the purported benefits of the project but are not. LDEQ cannot adequately discharge its

[127] CFI, 3Q 2025 Form 10-Q Quarterly Report (Nov. 6, 2025) at 24.

constitutional public trust duty without this information, and it is LDEQ's obligation to ensure that CFI provides this information.

2. The EAS does not include *any* discussion of potential environmental justice issues.

As LDEQ is aware, the First Circuit Court of Appeal of Louisiana recently affirmed that LDEQ's public trustee duty encompasses a requirement to conduct an environmental justice analysis. *Rise St. James v. LDEQ*, 383 So.3d at 987. The First Circuit opinion incorporated the EPA's (then) definition for environmental justice:

> The fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies," with "fair treatment" meaning that "no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial operations."

Id. at 988.

Neither CFI's EAS nor LDEQ's Statement of Basis mention environmental justice at all, let alone analyze whether there is any risk that emissions from this Facility may result in a disproportionate pollution impact on local communities. Such an analysis is especially important here because the area immediately surrounding the proposed Facility site already has a particularly heavy industrial presence, and LDEQ has recently approved the construction of multiple new large facilities in the immediate area—including at least one other ammonia plant—and is considering applications for additional facilities.[128] At a minimum, CFI's EAS should have evaluated the existing air pollution burden and risk for the communities in the area around the Facility, using tools such as EPA's EJ Screen.[129]

A brief review of the EJ Screen tool (hosted by the Public Environmental Data Partners) shows that the area within a 5-mile radius of the proposed Facility is already exposed to high levels of cumulative pollution impact, and is at *especially* high risk of exposure to toxic pollutants, such as ammonia. For example, the EJ Screen tool shows that the area within a 5-mile radius of the Facility is at-or-well-above the 80th percentile mark in the state of Louisiana on several key metrics, including toxic releases to air, PM2.5 exposure, ozone exposure, hazardous waste proximity.[130] In particular, this area is in the 99th percentile—both nationally and within the state of Louisiana—for toxic releases to air, at a rate of roughly **21 times** the state average and **67 times** the national average. The area is also in the 90th percentile for ozone emissions, 97th

[128] This includes a new 2.7-gigawatt natural gas power plant in Donaldsonville which Clean Hydrogen Works applied for just last month, which proposes to add an additional 168.81 tpy in permitted ammonia emissions to the area. https://edms.deq.louisiana.gov/app/doc/view?doc=15002539

[129] EPA's version of EJ Screen is no longer available. However, the Public Environmental Data Partners, a volunteer coalition of nonprofit researchers and policy organizations, have created and hosted an unofficial mirror of EPA's EJ Screen tool, which is identical to the original EJ Screen and easily available online.

[130] https://ejamapi-84652557241.us-central1.run.app/report?lon=-91.024421&lat=30.18327&buffer=3

percentile for RMP proximity, 87th percentile for hazardous waste proximity, and 80th percentile for PM2.5 emissions. The proposed Facility will be located right across the Mississippi River from multiple residential communities and just north of Donaldsonville, and EJ Screen indicates 6,014 people live within that five-mile radius. The National Center for Education Statistics' School & District Navigator shows that at least two schools, Lowery Elementary School and Lowery Middle School, are located within that five-mile zone as well.

These environmental burden indicators are significant and and should be included in LDEQ's analysis of the IT factors. CFI's EAS contains no analysis at all of the pollution burden of the area around this proposed Facility, and LDEQ cannot satisfy its burden without examining this issue.[131]

3. The EAS provides no discussion of potential ammonia or CO2 leaks, or accident prevention and minimization programs.

LDEQ has a duty to ensure that the proposed Facility will have sufficient measures in place to minimize the risks of accidental releases of hazardous materials to the public and the environment, and to assess how any accidental releases could impact residents and further exacerbate existing disproportionate impacts in communities, particularly in the face of increasingly intense storms and worsening flood risks that are likely to affect the Facility over the coming decades. Of particular concern are potential accidental releases from CO2 pipeline ruptures.

Ammonia is listed as an "extremely hazardous substance" under the federal Emergency Planning and Community Right-to-Know Act, 40 CFR Part 355, Appendices A and B, as well as a hazardous substance under the federal Comprehensive Environmental Response, Compensation, and Liability Act. 40 CFR 302.4. It is also a toxic air pollutant regulated by and subject to an 8-hour average ambient air standard of 640 ug/m^3 under Louisiana's TAPs program. LAC 33:III.5112, Table 51.2. Exposure to airborne ammonia can cause both short-term and chronic respiratory health effects, and the chemical is lethal at sufficiently high concentrations. In addition, ammonia re-deposits onto soils and into sensitive waterways, resulting in soil acidification and eutrophication, which are destructive to both terrestrial and aquatic ecosystems. Ammonia also combines with other pollutants in the atmosphere to form particulate matter, which is itself a criteria pollutant that threatens public health and is one of the primary contributors to regional haze issues. Chronic exposure to low concentrations of ammonia can lead to respiratory issues such as coughing, wheezing, and shortness of breath.

According to Louisiana's detailed point source emission inventory for 2024, available on its online Emissions Reporting and Inventory Center,[132] total annual ammonia emissions from point sources in the state were approximately 9,973 tons per year. Of these, roughly 4,684 tons per year—or approximately 47% of ammonia emissions for the entire state—are emitted from

[131] Commenters expect that CFI's explanation for why it never discusses potential EJ issues would be that there is no need to consider whether there are any disparate impacts because its compliance with the NAAQS and Louisiana ambient air standards show that there are no "adverse impacts." This is inapposite, as Commenters analyses show that CFI is not in compliance with either.
[132] Available online via LDEQ's website at: https://deq.louisiana.gov/page/eric-public-reports

sources located in Ascension Parish. Further, using LDEQ's permitted/actual emissions by radius report function for ERIC reports show that sources permitted within a 5-mile radius of the proposed Facility site already emit 1,145 tons per year of ammonia.[133] The proposed Facility would add an additional permitted 143.61 tpy to this already excessive ammonia pollution burden. Ensuring adequate mitigation measures for accidental release of additional ammonia emissions is especially important because, as discussed previously in these comments, CFI's application substantially underestimated the Facility's fugitive ammonia emissions, ammonia modeling including ammonia emissions from nearby facilities shows that modeled ammonia concentrations exceed Louisiana's ambient air standard for ammonia by a significant margin, and LDEQ currently does not operate any ammonia stationary monitors nearby that would help determine whether ambient ammonia concentrations comply with the state standard or exceed health-based guidelines. CFI's EAS states vaguely that "the requirements of Louisiana Administrative Code, LAC Title 33:111.Chapter 59, Chemical Accident Prevention and Minimization of Consequences, will be met by the facility," and that the proposed Facility "will have response plans (i.e., Emergency Response Plan, Spill Prevention Control and Countermeasure Plan (SPCC), Facility Response Plan, Risk Management Plan, and a Contingency Plan) in accordance with state and federal regulations that apply"—but provides no specifics of these plans. Draft Permit Package at 455-456. This lack of detail is especially concerning given that the only actual requirement for ammonia leak detection in the Draft Title V permit consists of daily "[a]udio, olfactory, and visual checks" for leaks. Draft Title V Permit Condition 155.

Similarly, because CO2 is corrosive when dissolved in water, pipelines that transport CO2 are at risk of leakage or catastrophic rupture.[134] Carbon dioxide is denser than air, and consequently, if there is a leak or rupture, CO2 will move as a plume along the ground, displacing air (and hence oxygen).[135] Among other health effects, the displacement of oxygen by CO2 can cause loss of consciousness and death by asphyxiation.[136] Furthermore, as demonstrated by the February 22, 2020, CO2 pipeline rupture in Satartia, MS, a CO2 release can impede first responders by causing vehicles with internal combustion engines, which rely on oxygen, to stop working.[137]

Yet CFI provides no information at all on where those pipelines are located. LDEQ's public trustee duty requires it to consider reasonably foreseeable potential impacts, such as those

---

[133] Using a radius of 8,046 meters (approximately 5 miles) centered on Latitude 30.183459 decimal degrees and longitude -91.024400 decimal degrees.

[134] Pipeline Safety Trust, Summary for Policymakers: Carbon Dioxide Pipeline Safety, May 2023, available at https://pstrust.org/wp-content/uploads/2023/06/carbon_dioxide_pipeline_safety_summary_6_21_23.pdf.

[135] Pipeline and Hazardous Materials Safety Administration, Failure Investigation Report – Denbury Gulf Coast Pipelines, LLC – Pipeline Rupture/Natural Force Damage, May 26, 2022, available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf.

[136] *Id.*

[137] *Id.*; Julia Simon, The U.S. is expanding CO2 pipelines. One poisoned town wants you to know its story, *National Public Radio*, September 25, 2023, available at https://www.npr.org/2023/05/21/1172679786/carbon-capture-carbon-dioxide-pipeline.

that might result from a CO2 pipeline rupture. In order for LDEQ to properly evaluate all risks and potential mitigation measures associated with this project, CFI needs to actually explain the siting details for the proposed CO2 pipelines that will be transporting the Facility's CO2 stream for CCS. This is especially important given that at least two schools, Lowery Elementary School and Lowery Middle School, are located within five miles of the Facility. We also note that though 1PointFive's website does not provide a specific location for the proposed Pelican Sequestration Hub, it indicates that it will be located in Livingston and St. Helena Parishes—which are located to the northwest across the Mississippi from Modeste.[138] If this is indeed the CCS facility that CFI intends to use, this would suggest that CFI would need anywhere between 30-50 miles of CO2 pipelines that are likely to run through multiple residential communities, towns, and cities between Modeste and those parishes, such as Geismar and Gonzales. Though our understanding is that the pipeline itself will be owned by a third party (and not CFI itself), CCS is central to the purpose of this Facility and it is CFI's CO2 stream—which its permit application shows has a significant methanol and VOC content—that will be running through those pipes. The risks associated with transporting CFI's CO2 stream must be adequately evaluated by LDEQ, regardless of whether CFI provides that information itself.

4. CFI provides no information regarding emissions from the marine terminal or shipping operations.

The Facility will include a dedicated marine terminal on the Mississippi River, where its ammonia product will be loaded and shipped for sale. As already noted previously, though CFI's revised permit application estimates annual fugitive ammonia emissions of 5.40 tpy from ship loading based on an assumed 40 ships per year,[139] CFI did not consider any other emissions from the marine vessels during loading operations. The EAS also does not include any information at all about its expected shipping operations—including what class or size vessels it expects the terminal to accommodate, or what primary fuel source those vessels will use.[140] It is difficult to assess the full potential air pollution impact of the marine terminal without these basic details.

5. The cultural resources study is not in the permit record.

It is not clear from the permit record whether a full survey has been conducted of all areas of the site slated for development or impacted by development. CFI's EAS states that a "Phase I Cultural Resources Survey of the subject property was completed in October 2018," and that based on the results of this survey and CFI's plans, "there are no anticipated archeological impacts." Draft Permit Package at 478. However, this phase I cultural resources survey does not appear to be included in the draft permit package or application materials, and Commenters are unable to locate a copy of it online. Thus, the public has had no opportunity to review the adequacy and conclusions of the study, and this precludes the public from raising issues and submitting comments about the study.

---

[138] https://www.1pointfive.com/projects/pelican-hub

[139] Draft Permit Package at 281.

[140] Commenters note that the EAS itself never even states that the terminal will service an assumed 40 ships per year, and that this information is only found in the calculations for ammonia ship loading emissions.

It is especially important for the cultural resources survey to be available for a close review given the historical nature of the area immediately surrounding the proposed Facility's site and the rapid pace of industrial development that has recently been approved in this area. As LDEQ is aware, Ascension Parish, including Modeste, was the site of many former plantations, such as the Mulberry Grove Plantation and the Babin Place Plantation.[141] There has been at least one incident recently in which two historical structures were mistakenly demolished on the proposed site for the Hyundai steel mill, which immediately neighbors the parcel where CFI's Facility will be located and encompasses the site of the former Mulberry Grove Plantation.[142] LDEQ should proceed cautiously and deliberately in ensuring that the historical heritage of this area is not further damaged unnecessarily in the rush for development.

It is especially important to know the precise geographical scope that was used for the phase I cultural resources survey, as the project's footprint is not limited solely to the immediate ground upon which the Facility will be built. For example, CFI's EAS states that "[n]atural gas and several other raw materials will be received by pipeline." Draft Permit Package at 477. There will also be a number of pipelines carrying CFI's CO2 stream to an unspecified location for CCS. The areas through which these pipelines will run are clearly also areas that would be impacted by the development of the project and should be included in the scope of the cultural survey.

Again, because CFI has not provided any information on potential routes for the pipelines that will be carrying either materials to this Facility or its CO2 stream for CCS, and because CFI has not included the phase I cultural resources survey, it is difficult for the public to know the precise expected scope of this project's footprint in the area or to evaluate the adequacy of the survey. At a minimum, LDEQ should require CFI to produce the phase I cultural resources survey as a part of the permit record, and to provide specific details regarding pipeline routes.

6. Potential adverse impacts from operation are not adequately addressed.

We note that despite a significant number of changes between the 2023 and 2025 applications, including (multiple) revisions to the assumed CCS rate and the replacement of the steam methane reforming process with the autothermal reforming process, the EAS included with the Revised Application in 2025 is, with the exception of a few very minor changes (primarily to update dates and to revise the projected tons per day of the Facility), basically

---

[141] *See generally* U.S. Army Corps of Engineers, New Orleans District. *History and Archaeology of Babin Place Plantation, Ascension Parish, Louisiana.* 2021. (Last accessed Dec. 5, 2025). https://www.crt.state.la.us/Assets/OCD/archaeology/discoverarchaeology/virtual-books/PDFs/Babin_Place.pdf

[142] WBRZ Staff. "After WBZR report, Hyundai asks Mulberry Grove to stop tearing down buildings at site of planned steel mill." WBRZ. (Oct. 28, 2025). Last accessed Dec. 5, 2025. Available at : https://www.wbrz.com/news/after-wbrz-report-hyundai-asks-mulberry-grove-to-stop-tearing-down-buildings-at-site-of-planned-steel-mill/;
Michael Tortorich. "Hyundai Steel responds after historic structures demolished in Ascension Parish." Gonzales Weekly Citizen (Oct. 28, 2025). Last accessed Dec. 5, 2025. Available at: https://www.weeklycitizen.com/story/news/local/2025/10/28/hyundai-steel-responds-after-historic-structures-demolished-in-modeste/86956346007/

identical to the EAS that was included in the original 2023 application. This is because neither EAS contains any actual discussion of the process units at the Facility, or actual design and operation of the Facility, and each more or less relies entirely on CFI's conclusion that all potential adverse environmental impacts have been minimized to the extent possible by definition of CFI's compliance with the NAAQS, PSD increments, and applicable state and federal requirements. Yet as discussed extensively in our comments above, the draft permits are severely deficient and do not comply with the requirements of the Clean Air Act, and a review of CFI's emission estimates and deficient modeling shows that emissions from the Facility not only exceed the PSD increment for multiple additional pollutants, but are also likely to contribute to a violation of the ozone NAAQS and Louisiana's ambient air standard for ammonia.

C. The Draft Permits are severely deficient and do not comply with the requirements of the Clean Air Act.

As a preliminary matter, LDEQ must go beyond evaluating whether the application complies with applicable laws where necessary to demonstrate that the project avoids potential environmental harm to the maximum extent possible. *Save Ourselves*, 452 So.2d at 1160 ("[I]t appears that the agency may have erred by assuming that its duty was to adhere only to its own regulations rather than to the constitutional and statutory mandates."). Yet CFI relies heavily on claims that the project will be constructed and operated in compliance with the Clean Air Act to show the project minimizes environmental impacts. Regardless, many of the conclusions stated in the EAS are simply incorrect—in particular, CFI's conclusions related to the expected environmental impacts and projected emissions from the proposed project.

CFI's "analysis" leans heavily on its claim that it is complying with all applicable requirements of the Clean Air Act. For example, in its section addressing factor one ("potential and real adverse environmental effects") CFI states that projected emissions from the project are protective of the NAAQS, applicable PSD increments, and Louisiana's TAPs ambient air standards, which were "designed from inception to protect human health and the environment with an ample margin of safety." Draft Permit Package at 452. Elsewhere, CFI concludes that air impacts have been minimized to the maximum extent possible because NAAQS are health standards and "by definition, compliance with the NAAQS demonstrates that no adverse impacts will result as the standards have been set conservatively to protect even sensitive individuals with an adequate margin of safety, and without regard to the cost of compliance." Draft Permit Package at 456.[143] Similarly, CFI also states that adverse environmental effects have been avoided to the maximum extent possible because this Facility is applying BACT, and "the BACT top-down analysis inherently requires that real adverse environmental effects will be avoided to the maximum extent possible." Draft Permit Package at 458.[144] Similarly, CFI's response

[143] Commenters note that this premise is not entirely accurate. The NAAQS are intended to provide a benchmark. That does not mean levels below NAAQS are risk-free, and EPA has previously stated that even levels below NAAQS may have health impacts. https://www.epa.gov/sciencematters/study-shows-low-levels-air-pollution-pose-risk-older-adults#:~:text=5%20concentrations%20were%20lower%20than,New%20England%20Journal%20of%20Medicine.

[144] This of course assumes that CFI has actually performed the necessary BACT analyses. CFI has not.

regarding factor two, "cost benefit analysis of environmental impact costs," concludes that environmental impact costs are attributable to "adverse environmental effects," and that all adverse environmental effects have been mitigated because "the facility will be in compliance with all air, water, and waste regulatory programs designed to ensure protection of human health and the environment with an ample margin of safety." Draft Permit Package at 467.

But as discussed at length in the sections above, a review of the permit materials shows that the permits fail to meet these requirements in multiple ways. For example:

- For multiple sources of emissions, CFI has either substantially underestimated emissions or failed to include emissions at all.

- CFI has provided no information to support its claimed 89% CCS rate, which evidence from similar facilities suggests is unrealistic and unachievable in practice.

- Relatedly, CFI's conclusions that its emissions are below the PSD de minimis thresholds for PM10, PM2.5, and VOCs are incorrect (for many, many reasons). CFI is in fact over the threshold for all three pollutants and must be required to perform a full BACT analysis for each.

- CFI's BACT analysis for NOx is deficient. CFI's air modeling for NOx emissions is similarly deficient.

- CFI's ozone impacts analysis is deficient and does not demonstrate compliance with the 8-hour Ozone NAAQS.

- CFI has likely substantially underestimated ammonia emissions, and ammonia modeling shows that ammonia emissions from the Facility exceed Louisiana's ambient air standard for ammonia.

- And finally, the Draft Title V Permit is seriously deficient, and nearly all of its limits are unenforceable as either a legal or practical matter, and have no associated testing or monitoring conditions.

Given the extensive list of serious issues with the permits identified above, the significant gaps in information provided in CFI's EAS, and the lack of any evidence in the permit record suggesting that LDEQ has performed any evaluation of the IT factors beyond simply incorporating CFI's own ESA (without any apparent scrutiny of the information within), Commenters do not believe LDEQ can reasonably claim to have satisfied the requirements of its constitutional public trustee duty.

At a minimum, LDEQ must require CFI to provide the additional information as necessary for LDEQ to perform its own independent evaluation of the IT factors; actually evaluate the information provided by CFI and explain its own basis for each IT factor clearly in the permit record; and revise the proposed permits to correct the severe deficiencies identified above and to ensure that they comply with the requirements of the Clean Air Act.

CONCLUSION

For all of the reasons set forth above, the draft permits are substantially deficient, do not meet the minimum requirements of the Clean Air Act, and cannot be issued in their current form. LDEQ must demonstrate that the construction and operation of the proposed project will comply with the Clean Air Act before it approves the project, require CFI to submit the additional information needed to evaluate the IT factors, and perform its own evaluation of the IT factors as required under its constitutional public trustee duty.

Commenters would like to thank LDEQ for the opportunity to comment on these draft permits and LDEQ's consideration of these comments. If you have any questions regarding our comments, please do not hesitate to contact Sanghyun Lee, of the Environmental Integrity Project, at any time—either at slee@environmentalintegrity.org or at (202) 263-4441.

Respectfully submitted,

/s/ Sanghyun Lee
Sanghyun Lee, Senior Attorney
Environmental Integrity Project
650 Poydras Street, Suite 1400-6800
New Orleans, LA 70130
(202) 263-4441
SLee@environmentalintegrity.org

/s/ William Most
William Most (La. Bar No. 36914)
Most & Associates
201 St. Charles Ave., Ste. 2500, # 9685
New Orleans, LA 70170
(504) 509-5023
williammost@gmail.com

Ashley Gaignard
President
Rural Roots Louisiana
ashley@ruralrootslouisiana.org

Tyler Weiglein
Engineering Analyst
Environmental Integrity Project
tweiglein@environmentalintegrity.org

Anne Rolfes
Director
Louisiana Bucket Brigade
4731 Canal St.
New Orleans, LA 70119
anne@labucketbrigade.org

Enclosed as attachments:

Attachment 1	Comments on Proposed Permits by Petra Pless, D.Env. (Pless Report)
Attachment 2	Exhibits 1-27 for the Pless Report
Attachment 3	Review of Ozone Modeling for the Proposed CF Industries Blue Point Facility (Battye Ozone Report)
Attachment 4	Review of Ammonia Modeling for the Proposed CF Industries Blue Point Facility (Battye Ammonia Report)