



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
RESEARCH TRIANGLE PARK, NC 27711

AUG 26 2011

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Semiconductor Industry Association  
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Washington, D.C. 20005

OFFICE OF  
AIR QUALITY PLANNING  
AND STANDARDS

Dear Mr. Isaacs:

The U.S. Environmental Protection Agency has received your letter dated July 29, 2011, in which you have articulated concerns about permitting for the semiconductor industry after the implementation of the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Tailoring Rule (the "Tailoring Rule"). In particular, your letter requested information on the following areas related to the application of PSD to semiconductor manufacturing facilities:

1. Treatment of a semiconductor fabrication building (fab) as an "emissions unit" for purposes of determining PSD applicability.
2. Addressing the day-to-day changes for PSD applicability determinations.
3. Treatment of control measures when determining projected actual emissions (PAE).
4. Use of GHG Plantwide Applicability Limits (PALs).

We understand from your letter that the regulation of GHGs will trigger PSD permitting requirements for some semiconductor manufacturing facilities for the first time. Your letter explained that fabs may make changes on a daily basis and that the ability to make those changes quickly is critical. Our responses to your questions are designed to help the semiconductor industry understand and comply with their PSD requirements.

#### Background - The Semiconductor Industry

On January 2, 2011, GHG emissions from stationary sources became covered by the PSD permitting program for the first time. Additionally, GHG emissions first became subject to the title V operating permits program as of July 1, 2011. Semiconductor sources may now trigger permitting requirements under these two programs because of their GHG emissions. In the past, semiconductor sources have been able to avoid major source permitting requirements (i.e., PSD and title V) by implementing a series of control measures and accepting minor source emissions caps that kept them below major source thresholds. This approach has provided the semiconductor industry with needed operational flexibility.

Over the past 15 years members of the semiconductor industry have achieved reductions in fluorinated GHG emissions, including perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF<sub>6</sub>), through process optimization, use of alternative chemistry, and emissions abatement (i.e., installation of air pollution control equipment). In large part, the reductions are attributable to a

voluntary partnership<sup>1</sup> between the Semiconductor Industry Association (SIA) and the EPA that pursuant to a memoranda of understanding. As part of the partnership, member companies committed to reduce emissions of fluorinated GHGs and to track and annually report those emissions. In most cases, voluntarily installed GHG emission controls were not incorporated into facility air permits because there were then no underlying applicable Clean Air Act requirements. SIA reports that GHG emission control devices were applied to etch and chamber clean processes primarily at newer fabrication plants. The most common technologies used are high temperature oxidizers followed by wet scrubbers to remove by-products.

### Specific SIA Questions

#### **I. Treatment of a Semiconductor Fab as an “Emissions Unit” for Purposes of Determining PSD Applicability**

In your letter you indicate that in minor source permitting of semiconductor manufacturing facilities, by local and state air permitting agencies, each fab at a facility is normally treated as an individual emissions unit.<sup>2</sup> You are now seeking confirmation that it is appropriate to treat each semiconductor fab at a manufacturing facility as a single emissions unit for the purposes of determining PSD applicability. This approach seems appropriate because of the interconnected nature of the “tools” in the fab. Similarly, the systems that deliver materials to those tools and manage their discharges have also generally been treated as part of the emissions unit.

Often, an “emissions unit” is assumed to be a single piece of process equipment or activity. However, many pieces of related process equipment grouped together may also fit within the definition of “emissions unit” under the federal PSD regulations. In order to determine how the “emissions unit” should be defined in this case we first look to the definition of “emissions unit” found at 40 CFR §52.21(b)(7).

Emissions unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section:

- (i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.
- (ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.

Additionally, although not determinative, New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) can be sources of information that may be

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<sup>1</sup> PFC Reduction/Climate Partnership for the Semiconductor Industry; see <http://www.epa.gov/semiconductor-pfc>.

<sup>2</sup> Some examples where this approach has been used are: IBM East Fishkill Facility in Hopewell Junction, NY title V permit; Vitesse Corp in Colorado Springs, CO state operating permit; Renesas Electronics in Roseville, CA operating permit; and Micron Technology in Boise ID construction and operating permit.

helpful in defining an emission unit. In this case NESHAP Subpart BBBBB- National Emission Standards for Hazardous Air Pollutants for Semiconductor Manufacturing provides relevant information on what a semiconductor manufacturing process unit might be. NESHAP Subpart BBBBB states that:

A semiconductor manufacturing process unit includes the equipment assembled and connected by ductwork or hard-piping including furnaces and associated unit operations; associated wet and dry work benches; associated recovery devices; feed, intermediate, and product storage tanks; product transfer racks and connected ducts and piping; pumps, compressors, agitators, pressure-relief devices, sampling connecting systems, open-ended valves or lines, valves, connectors, and instrumentation systems; and control devices.

Our past guidance on the treatment of “emissions units” in other industries is consistent with this approach. In a letter issued by the EPA Region III on November 30, 2000, the EPA provided guidance regarding a proposed PSD modification at a DuPont facility.<sup>3</sup> The guidance indicated that DuPont’s proposed project could be considered a modification to a single emissions unit. The emissions unit was defined as the entire solvent-spun synthetic fiber process that included the spinning, wash/draw, and solvent recovery operations. Similarly, in guidance issued by the EPA Region VIII dated February 6, 1990, regarding a determination of Lowest Achievable Emission Rate (LAER) for Coors Container,<sup>4</sup> the EPA determined that an emissions unit consisted of the entire coating operation (topcoat, basecoat, etc). In both determinations the NSPS definition of emissions unit was relied upon; the rule provided a rationale for grouping the processes together to create a single emission limitation covering all of the equipment. This was the most technically-achievable and cost-effective way to evaluate control for these operations.

Given the flexibility provided for in the PSD definition of emission unit, considering the treatment of semiconductor facilities under the NESHAP, and considering our previous guidance on this matter we believe that the treatment of a fab as an emissions unit for PSD applicability purposes is appropriate. We believe it would usually be consistent with the federal definition of “emissions unit” to include in the fab “emissions unit” the integrated contiguous clean room space, including all the tools, and systems that support the activities in the clean room. The fab emissions unit could be located in a single building or adjoining buildings as long as it is physically connected, integrated, and operated as a continuous clean room space. However, if a building or facility were to contain more than one physically separated and independent clean room, we believe it would generally be appropriate to treat those fabs as separate emissions units. Air pollutant control equipment that serves more than one fab may need to be treated as a separate emissions unit under the relevant regulatory definition of “emissions unit,” for example a regenerative thermal oxidizer (RTO) that serves multiple fabs to control volatile organic compounds (VOC) emissions will emit GHGs and should be treated as a separate emissions unit. Not all control equipment will have additional emissions beyond that which they control, this needs to be considered when determining how fabs and their control equipment are treated as emissions units. We believe that it would generally be consistent with the federal definitions of “emissions unit” to treat equipment serving

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<sup>3</sup> U.S. EPA, Region III, to John Daniel, Director, Air Program Coordination, Commonwealth of Virginia, Department of Environmental Quality, 30 November 2000.

<sup>4</sup> U.S. EPA, Region VIII, to Brad Beckham, Director, Air Pollution Control Division, Colorado Department of Health, 6 February 1990.

multiple fabs (such as boilers, emergency generators, and similar auxiliary equipment), that are operated separately and are often located in a separate building, as separate emissions units.

When conducting a PSD applicability determination, all emissions increases from emission units associated with, or affected by a project must be included in the calculations. Applied to the fab, this means that the PSD applicability determination would look at the overall increase across the entire fab emissions unit from a project, not the specific changes at each particular tool or other system within the fab. Implementing state and local agencies may adopt different and potentially more stringent or less flexible requirements under their SIP-approved minor or major New Source Review (NSR) programs. We encourage you to work with your reviewing agencies to confirm the specific requirements applicable to individual semiconductor manufacturing facilities.

## II. Addressing the “day-to-day changes” for PSD applicability determination

In your letter you indicated that a number of semiconductor fabs undergo dozens of small changes each year as the production methods and operations are maintained, updated, adjusted and refined. You proposed three approaches or methods for practical and efficient PSD applicability determination for such changes described in your letter as “day-to-day changes” and requested whether each of the proposed methods would provide an adequate record of PSD non-applicability.

First, we would like to clarify that our response to this request on “day-to-day changes” assumes that the subject facilities are potentially major PSD sources only due to GHG emissions (i.e., potential emissions of all non-GHG regulated NSR pollutants are assumed to be below major source thresholds both before and after the project at issue). Accordingly, we are limiting our response to PSD applicability procedures and requirements applicable to GHGs, more specifically to the established “subject to regulation” thresholds for GHGs, based on carbon dioxide (CO<sub>2</sub>) equivalent (CO<sub>2</sub>e) emissions.<sup>5</sup> This is consistent with the context of the SIA’s proposed applicability determination methods and our understanding that many semiconductor manufacturing facilities are potentially major sources under PSD only due to GHGs.

We summarized the three SIA proposed PSD applicability determination methods below with our corresponding responses.

**SIA’s Proposed Method 1 – This method would apply when the Projected Actual Emissions of the fab are well below 75,000 tpy CO<sub>2</sub>e. In such a case, if it is determined that the change does not increase the Projected Actual Emissions, this determination will serve as a record that the change cannot trigger PSD. Under this method, the fab owner would create and record an assessment of the Projected Actual Emissions and the review of each change would be a simple determination that the project will not increase the Projected Actual Emissions.**

Under 40 CFR 52.21(b)(49)(v)(b) GHGs are subject to regulation for an existing stationary source that emits or has the potential to emit 100,000 tpy CO<sub>2</sub>e, when the source undertakes a physical change or

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<sup>5</sup> 40 CFR 52.21(b)(49). As a result of the Tailoring Rule, GHGs are treated differently from non-GHG regulated NSR pollutants under the PSD program. EPA has published detailed guidance on PSD applicability determinations and other permitting requirements for GHGs. See <http://www.epa.gov/nsr/ghgpermitting.html>.

change in the method of operation that will result in an emissions increase of 75,000 tpy CO<sub>2</sub>e or more. The term “emissions increase” in this context means both a significant emissions increase as calculated under 52.21(a)(2)(iv) and a significant net emissions increase as defined in 52.21(b)(3) and (b)(23).<sup>6</sup> Under 52.21(a)(2)(iv) whether an emissions increase occurs for a project involving only existing emissions units (e.g., an existing fab) is determined using the actual-to-projected-actual emissions test. In summary, that test involves calculating baseline actual emissions and projected actual emissions for each emissions unit affected by a project and calculating the project emissions increase as the sum of the differences between projected actual emissions and baseline actual emissions for each unit.<sup>7</sup> The definition of projected actual emissions provides that the owner or operator may exclude, in calculating the increase from a particular emissions unit, that portion of the unit’s emissions following the project that the unit could have accommodated in the selected baseline actual emissions period and that are also unrelated to the project.<sup>8</sup>

SIA’s proposed Method 1 relies on a simplified version of the actual-to-projected-actual emissions test as an initial screen for purposes of determining whether there is a significant emissions increase in evaluating whether GHGs are subject to regulation for a project that, under certain circumstances, may provide a streamlined approach to these calculations. Because the proposed approach ignores baseline actual emissions, thereby assuming baseline actual emissions equal zero, and because it does not exclude any of the fab emissions following the project in determining the increase, it represents a conservative estimate of the increase in emissions occurring from the fab as a result of the project. Moreover, if the projected actual emissions alone from a fab do not exceed 75,000 tpy CO<sub>2</sub>e, the calculation of significant emissions increase under the actual-to-projected-actual test for that fab would also not exceed 75,000 tpy CO<sub>2</sub>e, such that GHGs would not be subject to regulation for that project, assuming the fab was the only affected emissions unit.

In general, we find Method 1 acceptable as an initial screen for purposes of determining that there is not a significant emissions increase in GHGs from a project in order to determine whether GHGs are subject to regulation for that project. If GHGs are not subject to regulation for a project, PSD would not be triggered due to GHG emissions increases resulting from the project at a fab. However, we would like to clarify certain additional requirements. First, our aggregation policy, discussed in further detail in our response to SIA proposed Method 3, requires that nominally separate changes that are sufficiently related based on established criteria be aggregated into a single common project for the purpose of determining PSD applicability.<sup>9</sup> Accordingly, owners or operators should evaluate “day to day changes” to determine the proper aggregation of such changes prior to evaluating PSD applicability. Second, our interpretation of the Clean Air Act and long standing policy requires that calculations of project emissions increases include not only those increases occurring from new or modified emissions units but also affected non-modified units.<sup>10</sup> For example, a modification to an existing semiconductor facility fab

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<sup>6</sup> 40 CFR 52.21(b)(49)(iii).

<sup>7</sup> 40 CFR 52.21(a)(2)(iv)(c).

<sup>8</sup> 40 CFR 52.21(b)(41)(ii)(c).

<sup>9</sup> For a collection of prior EPA memoranda relevant in determining whether projects should be aggregated, please see 75 FR 19570-71 (April 15, 2010). While the policy discussion in this reconsideration notice does not represent a final agency position without further action by the agency, the numerous memoranda cited in this notice stand for themselves as examples of our historic approach to aggregation.

<sup>10</sup> The regulations define a “major modification” as one in which a physical change or a change in the method of operation of a major stationary source results in a significant emissions increase of a regulated NSR pollutant and a significant net

may result in increased steam demand from facility boiler(s). In that case, the boiler(s) could realize increased utilization on an annual basis (and a corresponding increase in GHG emissions) as a result of the changes in the fab and emissions from the boiler(s) must be evaluated using the actual-to-projected-actual emissions test to resolve the total emissions increase from the source that is related to the project.

Finally, your letter noted that the fab owner would create and record an assessment of projected actual emissions and requested what record is adequate to demonstrate PSD non-applicability. We believe that a record that is consistent with the recordkeeping, monitoring, and reporting provisions of 40 CFR 52.21(r)(6) would be adequate to document a determination of PSD non-applicability in this situation.

**SIA's Proposed Method 2 – A simple variation on Method 1 can be used to deal with day-to-day changes at fabs that have Projected Actual Emissions over 75,000 tpy CO<sub>2</sub>e. In this instance, the fab owner will also determine the Baseline Actual Emissions for a 24 month period in the prior ten years. If the difference between the Projected Actual Emissions and the Baseline Actual Emissions is well below 75,000 tpy CO<sub>2</sub>e, one applies the same approach as Method 1.**

Proposed Method 2 is a variation of Method 1 that incorporates baseline actual emissions into the calculation of whether a physical change or change in the method of operation at a stationary source that emits or has the potential to emit 100,000 tpy CO<sub>2</sub>e will result in a significant emissions increase of 75,000 tpy CO<sub>2</sub>e or more for purposes of determining whether GHGs are subject to regulation for the project. As long as the calculation of baseline actual emissions and projected actual emissions comports with the regulatory definitions of those terms, we believe this approach is acceptable for determining that no significant increase of emissions for GHGs occurred for the project and that GHGs are accordingly not subject to regulation for a project.<sup>11</sup> Our response to proposed Method 1 related to project aggregation, the consideration of all affected emissions units in the analysis, and appropriate recordkeeping also applies to proposed Method 2.

**SIA's Proposed Method 3 – Under this method, the fab owner starts each calendar year with an assessment of the range of changes that may occur in the upcoming year and then determines the nature of their CO<sub>2</sub>e impacts. At the start of the year, the fab owner completes the actual-to-projected-actual emissions calculation to determine the maximum emissions increase that could result from the full range of changes. That assessment can then be relied upon to address applicability for all the day-to-day changes for that year so long as the changes are consistent with and within the scope of changes laid out at the start of the year. A reassessment is triggered annually or with any mid-year departure from the plan of action that was assessed at the start of the year.**

Proposed Method 3 involves a project aggregation approach designed to reduce the burden of PSD applicability analyses for frequent, relatively minor physical and operational changes within a fab. EPA has addressed project aggregation in several letters, memoranda, and rulemaking preambles that

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emissions increase of that pollutant at the source. See 40 CFR 52.21(b)(2). Based on this, the total increase in emissions includes: (1) Increases occurring at all new or modified units, and (2) any other increases at existing emissions units not being modified that experience emissions increases as a result of the change. Increases occurring from units as a result of "debottlenecking" or "increased utilization" caused by a project must be included in determining NSR applicability for the project.

<sup>11</sup> Baseline actual emissions and projected actual emissions are defined in 40 CFR 52.21(b)(48) and (b)(41), respectively.

establish our interpretation of the Clean Air Act provisions related to “modification” and policy on project aggregation.<sup>9</sup> In brief, we look for indicia of relatedness among the individual actions at a source in order to determine whether the activities, in the aggregate, are one physical or operational change as those terms are used in the statute and regulations. We have made clear in past policy documents that the EPA may enforce the major source permitting requirements in cases when a source “circumvents” major NSR by dividing one change and its emissions increase into nominally-separate physical or operational changes. Our policy on aggregation outlines an approach relying upon case-specific factors (e.g., timing, funding, and the company’s own records) and the relationship between nominally-separate changes.

Our policy does not preclude the aggregation of multiple physical or operational changes when such changes taken together can be reasonably viewed as sufficiently related to be a single project even if individually or smaller groupings also could be viewed as physical or operational changes. So long as the grouping of changes aggregated together is consistent with our aggregation policies, does not result in circumvention of major modification permitting requirements, and does not create project netting opportunities that are inconsistent with the regulatory provisions and our policy, the group of changes may be assessed as one. The aggregation of multiple small changes that serve a common general purpose over the course of a reasonable planning or funding time period (such as one year) as described in your letter could qualify as a single project if the company’s own records and representations support that conclusion, again consistent with our policy-based project aggregation criteria. In such circumstances we find it acceptable and appropriate to consider the aggregate changes a single project within the fab.

Beyond the above relatively straight-forward context however, application of proposed Method 3 must take into consideration several additional factors to ensure compliance with applicable regulatory provisions and policy. First, where individual changes are aggregated for the purpose of applicability analysis and streamlining, and individual changes or smaller groupings of changes within the proposed aggregate ‘project’ appropriately could also be viewed as physical or operational changes, the owner or operator should consider only those changes that result in emissions increases in the projection in the first step of an applicability analysis and not any changes that result in emissions decreases when applying this method.<sup>12</sup> This is to ensure that project aggregation is not used as a mechanism to provide for “project netting”, which as indicated above is not allowed by the regulations.

Second, we would like to make clear that there is no presumption that a one year aggregation period is appropriate or justified for the purposes of determining major modification applicability. Owners or operators must carefully review all proposed physical or operational changes occurring at a source to ensure that they are appropriately aggregated in accordance with our policy-based criteria. Separating components of a project using proposed Method 3, for example- by accounting for some in one annual aggregation period and others in the next, could be considered circumvention of PSD permitting requirements if the increase calculated using proper project aggregation is significant.

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<sup>12</sup> We have made clear that only increases in emissions are accounted for under ‘Step 1’ of the major modification applicability procedures (the determination of the project emissions increase). In order to credit decreases in the applicability analysis, the owner or operator must perform a contemporaneous netting analysis (i.e., ‘Step 2’ of the applicability procedures). See, e.g., letter from Barbara A. Finazzo, U.S. EPA Region 2 to Kathleen Antoine, HOVENSA, L.L.C., “Re: HOVENSA Gas Turbine Nitrogen Oxides (GT NOx) Prevention of Significant Deterioration (PSD) Permit Application – Emission Calculation Clarification;” March 30, 2010.

Third, as described in our responses to proposed Methods 1 and 2 the applicability analysis is not limited to modified emissions units (e.g., an existing fab in this scenario) but rather must include all units at the source that could be affected by the project. This includes non-modified emissions units that are debottlenecked or could realize increased utilization as a result of the changes in the fab. Lastly, with respect to what would constitute an adequate record to document a PSD non-applicability determination, we believe that a record that is consistent with provisions of 40 CFR 52.21(r)(6) would be sufficient to document a determination of PSD non-applicability in this situation.

### **III. Treatment of unenforceable controls when determining projected actual emissions**

To determine PSD applicability (both for determining if GHGs are subject to regulation and when evaluating whether there is a major modification at an existing major stationary source), an owner or operator may use one of two tests to determine the emissions increase from an existing emissions unit: the “actual-to-projected-actual” emissions test or the “actual-to-potential” emissions test.<sup>13</sup> If the emissions unit at an existing source is new the owner or operator must use the “actual-to-potential” emissions test to calculate emissions increases at that unit. “Baseline actual emissions” are used to establish pre-project emissions for applicability purposes under both tests.

For an existing emissions unit that is not an electric utility steam generating unit, “baseline actual emissions” are generally the average rate in tons-per-year at which the unit actually emitted a regulated pollutant during any consecutive 24 month period (selected by the applicant) in the prior 10 years.<sup>14</sup> “Projected actual emissions” are the maximum annual rate, in tons-per-year that an existing unit is projected to emit a regulated pollutant in any one of the 5 or 10 years following the date the unit resumes regular operation after the project depending on whether certain regulatory criteria are met.<sup>15</sup> In calculating an increase using the “actual-to-projected-actual” emissions test the owner or operator may exclude the portion of the unit’s emissions following the project that an existing unit could have accommodated during the baseline actual emissions period and that are also unrelated to the particular project including any increased utilization due to product demand growth.<sup>16</sup> “Potential to emit” is the maximum capacity of a unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity to emit, 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 the unit’s design if the limitation or the effect it would have on emissions is enforceable as a practical matter.<sup>17</sup>

For the purpose of limiting potential to emit, air pollution control equipment or the effect it has on emissions must be enforceable as a practical matter. In general, this means that applicable permit

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<sup>13</sup> 40 CFR 52.21(b)(2)(iv) and (b)(41).

<sup>14</sup> 40 CFR 52.21(b)(48)(ii).

<sup>15</sup> 40 CFR 52.21(b)(41).

<sup>16</sup> 40 CFR 52.21(b)(41)(ii)(c).

<sup>17</sup> 52.21(b)(4). While the definition of “potential to emit” in the PSD regulations contains the term “federally enforceable,” this aspect of that decision was vacated in *Chemical Manufacturers Association v. EPA*, 70 F.3d 637 (D.C. Cir. 1995). See also *National Mining Association v. EPA*, 59 F.3d 1351, 1362-63 (D.C. Cir. 1995). We thus interpret this term to mean “federally enforceable or legally and practicably enforceable by a state or local air pollution control agency.” See, e.g., Interim Policy of Federal Enforceability Requirements for Limitations on Potential to Emit at 3-4 (Jan. 22, 1996). For simplification, we here use the term “enforceable as a practical matter” to encompass “federally enforceable or legally and practicably enforceable by a state or local air pollution control agency.”

conditions establish a legal obligation to install and operate the equipment and that compliance with the relevant permit limits can be verified. However, for calculating projected actual emissions, it is not required that air pollution control equipment or the effect such equipment has on emissions be enforceable to be considered, nor is it required that the projected emissions themselves be made enforceable. As such, when calculating projected actual emissions, in addition to considering legally enforceable restrictions, owners or operators may consider the effect on emissions of design or operational parameters, including air pollution control equipment, that are not enforceable.

Projected actual emissions should be calculated consistent with the criteria contained in the definition of that term.<sup>18</sup> Generally, projected actual emissions are based on the design and operational parameters that determine the emission rate per unit of production or time and projected annual production or utilization rate. For the purposes of projected actual emissions, the design and operational parameters can include air pollution control equipment installed and operated on a unit regardless of whether such equipment is legally enforceable. This approach provides consistency between the way voluntary controls are considered in calculating projected actual emissions and baseline actual emissions, thereby more accurately resolving increases in emissions resulting from physical or operational changes.

Notwithstanding the above conclusion, the burden is on the source owner or operator to ensure that projected actual emissions, including the effect of air pollution control equipment, are based on sound scientific information, are reasonable, and that air pollution controls are designed and operated consistent with representations made in the applicability calculations or else an emissions increase that could trigger PSD may occur. Capture and control efficiencies, outlet concentrations, or other metrics used to estimate controlled emissions should be supported by source test data, vendor design specifications, guarantees, or engineering calculations as appropriate. In circumstances where air pollution control equipment has been considered in determining projected actual emissions for one or more pollutants from an existing emissions unit, it is incumbent on the owner or operator to maintain and operate the equipment in accordance with good air pollution control practices, regardless of whether or not such equipment is legally enforceable. At a minimum this means that any manufacturer recommended operating and maintenance procedures are followed and that a record of any parameter monitoring performed, maintenance activities, and periods of control equipment downtime be maintained. It is important to stress that the EPA is authorized to take enforcement action for a violation of PSD if the projection is not consistent with the regulatory requirements.

#### **IV. Use of GHG Plantwide Applicability Limits**

We acknowledge your request for information as it relates to the use of PALs for the semiconductor industry. We are in the process of analyzing your request and the applicable regulations and will be responding to this aspect of your request in a subsequent letter to be issued in the coming weeks.

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<sup>18</sup> The definition of projected actual emissions specifies that owners or operators shall consider all relevant information, including but not limited to, historical operating data and the company's representations and highest projections of business activity. The definition also specifies that fugitive emissions, to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions shall be included. See 40 CFR 52.21(b)(41)(ii).

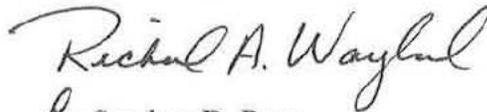
Conclusion

The responses to your questions provided in this letter and associated interpretations pertain to the Federal PSD regulations. Implementing state and local agencies may adopt different and potentially more stringent or less flexible requirements under their SIP-approved minor or major New Source Review (NSR) programs. We encourage you to work with your reviewing agencies to confirm the specific requirements applicable to individual semiconductor manufacturing facilities.

I appreciate this opportunity to respond to your questions, and I hope this response answers your questions. If you have additional questions, please contact Juan Santiago at (919) 541-1084.

Again, thank you for your letter. I appreciate the opportunity to be of service and trust the information provided is helpful.

Sincerely,



*for* Stephen D. Page  
Director  
Office of Air Quality Planning  
and Standards

cc: Janet McCabe, OAR  
Anna Marie Wood, OAQPS  
Phil Brooks, OECA  
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