UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
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Philadelphia, Pennsylvania 19103-2029

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ENVIRONMENTAL QUALITY BOARD

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June 27, 2014

Environmental Quality Board
P.O. Box 8477
Harrisburg, PA 17105-8477

RE: April 19, 2014 Proposal to amend Chapters 121 and 129, Additional Reasonable Available Control Technology (RACT) Requirements for Major Sources of Nitrogen Oxides (Nox) and Volatile Organic Compounds (VOCs)

Dear Ladies and Gentlemen of the Board:

Thank you for the opportunity to comment on proposed amendments to Chapters 121 and 129, "Additional RACT Requirements for Major Sources of NOx and VOCs", proposed on April 19, 2014, by the Environmental Quality Board.

The United States Environmental Protection Agency (EPA) has enclosed comments regarding the stringency of a number of the proposed emission limits. EPA believes that the proposed presumptive limits are too lax for certain electric generating utility boilers and other large coal fueled currently equipped with advanced controls beyond low NOx burners. Recent and past performance data reported to EPA shows that lower emission limits are technologically feasible. EPA believes that the Board and the Pennsylvania Department of Environmental Protection (PA DEP) need to re-evaluate emission limits for coal fueled boilers with advanced controls and set appropriately justified final RACT limits. Additionally, EPA believes that the Board and PA DEP need to re-examine the proposed presumptive limits and set appropriately justified final RACT limits in light of NOx emission limits set by nearby States, especially those limits which have been in effect for several years, given the benchmark cost effectiveness threshold used.

EPA has enclosed comments regarding the averaging compliance option because EPA believes that these provisions need to be amended to comport with the Clean Air Act as interpreted by the U. S. Court of Appeals for the District of Columbia Circuit. EPA also has comments dealing with implementation of the proposed requirements under a Title V program.

In the enclosures, EPA provides a summary of comments entitled "Enclosure 1. One Page Summary of EPA Comments on Proposed Amendments to RACT Emission Limitations [44 Pa.B. 2392, April 19, 2014". The additional enclosure and attachments provide more detailed comments, tables, and the relevant background or data.

EPA looks forward to working with you and PA DEP to resolve these comments. Please do not hesitate to contact me or Mr. Christopher Cripps of my staff at (215) 814-2179 for any questions pertaining to these comments.

Sincerely,

Diana Esher

Diana Esher, Director
Air Protection Division

Enclosures
cc: Joyce E. Epps, Director, Bureau of Air Quality, PADEP

Enclosure 1. One Page Summary of EPA Comments on Proposed Amendments to RACT Emission Limitations. [44 Pa.B. 2392, April 19, 2014]

I. Emission Limits for Certain Coal-fired Units: EPA advises the Board to revise allowable NOx emission limits for coal-fired boilers currently equipped with advanced controls such as selective catalytic reduction/ selective non-catalytic reduction/ammonia injection for those facilities or units which past actual emissions data show lower limits are certainly technically feasible. EPA has identified certain electric generation/cogeneration or fluidized bed boilers that have technology demonstrated to emit far below the proposed emission limits for coal fired combustion units. EPA believes that some lower limit than proposed is RACT for these units.

II. Other Emission Limits: EPA advises the Board to reevaluate the proposed presumptive RACT emission limits against current NOx emission limits currently in effect in other States as required by EPA's guidance on RACT for the 1997 and 2008 ozone NAAQS. EPA is advising that these States' emissions limits, representing recent conclusions by these other states about RACT or which were necessary to reach attainment, need to be considered and evaluated to determine if they are presumptively RACT for any categories of Pennsylvania sources. EPA has surveyed the limits in effect in those adjacent OTR States and provided a summary compilation.

III. Cost-Effectiveness: EPA advises the Board to reevaluate the proposed RACT limits by revising upward the cost effectiveness range to characterize RACT economic reasonableness and not to use a rigid "benchmark" to reject consideration of controls. Rather EPA's guidance is to consider for a source category control technologies whose range of cost effectiveness overlap an average benchmark. A reasonable average could be currently around $3,200 per ton and the upper bound around $5,500 per ton.

IV. Averaging Plans: EPA advises the Board to amend the averaging provisions of proposed section 129.98 to ensure that averaging plans including units inside designated nonattainment areas achieve at least RACT level reductions – excess reductions from outside any designated nonattainment area boundaries cannot be used to offset emissions above allowable RACT emissions inside any designated nonattainment area boundary. Such a change could be to prohibit averaging plans to include units outside each nonattainment area boundary or some other provision that is shown to achieve the same result. This change is necessary to conform to the Clean Air Act under the ruling of the Courts in *NRDC v. EPA*, 571 F.3d 1245 (D.C. Cir. 2009) in which the Court concluded that designated ozone nonattainment areas required to implement RACT must achieve RACT levels reductions inside the nonattainment area.

V. Title V Related: For better translation of rule requirements into Title V permits issued to sources subject to this rule, EPA advises the Board to include affirmative provisions in the rule itself to: (1) mandate that sources not using continuous monitoring systems (CEMS) to monitor compliance with periodic stack tests and parametric monitoring; (2) specify that a permit issued pursuant to proposed section 129.98(i) ensure the listing of "each air contamination source" at a Title V facility includes all NOx emitting sources at that facility; (3) require records be retained for at least 5 years; and (4) incorporate in Section 129.98 to: (a) identify what changes will mandate a change to the RACT averaging permit; (b) include actual start-up and shut-down emissions in compliance demonstrations; and (c) use the term "operating permit" and "operating permit modification" consistently.

VI. EPA recommends other minor editorial changes for clarity.

Enclosure 2: EPA Comments on Proposed Amendments to Chapters 121 and 129 Presumptive Reasonably Available Control Technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NOx) and volatile organic compound (VOC) emissions. [44 Pa.B. 2392, April 19, 2014]

I. Background:

On April 19, 2014 (44 Pa.B. 2392), the Environmental Quality Board (Board) proposed to amend Chapters 121 and 129 (relating to general provisions; and standards for sources) to read as set forth in Annex A. The proposed rulemaking would amend Chapter 129 to adopt presumptive reasonably available control technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NO_x) and volatile organic compound (VOC) emissions.

On June 6, 2013 (78 FR 34178) EPA proposed a rule titled "Implementation of the 2008 National Ambient Air Quality Standards for Ozone: State Implementation Plan Requirements" (hereafter the "State Implementation Plan (SIP) Requirements Rule"). This proposed rule will address the requirements for a range of SIP requirements for the 2008 ozone NAAQS, including requirements pertaining to attainment demonstrations, reasonable further progress (RFP), reasonably available control technology (RACT), the timing of SIP submissions and other Clean Air Act requirements for nonattainment areas as well as the revocation of the 1997 ozone NAAQS and associated anti-backsliding requirements.[1]

In the June 6, 2013 proposed SIP Requirements Rule, EPA proposed to continue EPA's long standing guidance on RACT although the proposed SIP Requirements Rule did note that certain aspects of RACT certifications issued in a November 29, 2005 rule were overturned after judicial review. EPA has long defined RACT as the "lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (78 FR 34178 at 34191, June 6, 2013 and 57 FR 55620 at 55624 November 25, 1992, both citing 44 FR 53761 at 53762, September 17, 1979). EPA noted in 1979 that when Congress passed the 1977 amendments to the CAA "Congress did not adopt its own definition of RACT and was well aware of how EPA used the Term" (44 FR 53761 at 53762, September 17, 1979) and notes that in the 1990 amendments to the CAA no statutory definition of RACT was added. EPA historically has recommended source-category-wide presumptive RACT limits especially for certain categories of volatile organic compound (VOC) sources and plans to continue that practice. EPA has also long allowed decisions on RACT be made on a case-by-case basis, considering the technological and economic circumstances of the individual source. For implementation of RACT for the 1997 ozone NAAQS EPA issued the "Phase 2" final rule on November 29, 2005 (70 FR 71612). The U.S. Court of Appeals for the District of Columbia Circuit ruled in *NRDC v. EPA*, 571 F.3d 1245 (D.C. Cir. 2009) that EPA had not demonstrated that some of the guidance in the Phase 2 rule regarding RACT implementation was consistent with the CAA. In that decision the Court rejected the notion that a regional cap-and-trade program intended to eliminate interstate transport of emissions consistent with section 110(a)(2)(D)(i) could automatically constitute

[1] While EPA has not yet finalized this Rule as of this present date, EPA is providing comments on Pennsylvania's proposed RACT provisions for the 1997 and 2008 ozone NAAQS based on our proposed implementation rule for 2008 ozone NAAQS.

RACT-level control as required by section 172(c)(1), but held open the possibility that such a program might in fact result in the same, or higher, level of emissions reductions in individual nonattainment areas (79 FR 32892 at 32896, June 9, 2014). The Court remanded the EPA's determination that compliance with the NOx SIP Call (63 FR 57356, October 27, 1998) regional cap-and-trade program would presumptively satisfy the area-specific RACT requirement (78 FR 34178 at 34182, June 6, 2013; 79 FR 32892 at 32896, June 9, 2014), and in the preamble for the June 6, 2013 proposed SIP Requirements Rule (78 FR 34178 at 34193) EPA preliminarily concluded that that the concerns expressed by the court about the agency's approach to the NOx RACT requirement for sources and the emissions reductions required by the NOx SIP Call raise significant questions about the EPA's approach to the comparable issues related to compliance with the Clean Air Interstate Rule (CAIR) promulgated on May 12, 2005 (70 FR 25162). In fact, EPA had requested a voluntary remand of the CAIR determination and vacatur of the CAIR presumption, which request was granted by the Courts (79 FR 32892 at 32896). On June 9, 2014 (79 FR 32892), EPA proposed to withdraw any prior determination or presumption, for the 1997 8-hour ozone national ambient air quality standard (NAAQS) that compliance with the CAIR or the NOx SIP Call automatically constitutes RACT for electric generating unit (EGU) sources participating in these regional cap-and-trade programs.

In the preamble for the June 6, 2013 proposed SIP Requirements Rule (78 FR 34178 at 34192), EPA noted that for the 2008 ozone NAAQS RACT requirements that States should use current EPA guidance and <u>any other information available</u> in making RACT determinations. The EPA recognized that existing Control Technique Guidelines (CTGs) and Alternative Control Techniques documents (ACTs) for many source categories have not been revised in a number of years. However, in most cases, more recent technical information is available in other forms, such as the BACT/LAER Clearinghouse; SIPs for other nonattainment areas as well as such things as emissions standards developed under CAA section 111(d) and settlement agreements related to enforcement of nonattainment new source review and prevention of significant deterioration regulations. EPA believes that "more recent technical information" logically includes actual emission rates achieved in practice by sources that have installed controls in response to a settlement agreement or in response to state rules adopted in response to the NOx SIP Call or the CAIR (see for example, 40 CFR 51.121-51.124) as well as Federal Implementation Plans (FIPs) (40 CFR 52.35 and Part 97) and actions on section 126 petitions (40 CFR 52.34) promulgated as a consequence of these rules.

In the case of sources which as part of a settlement agreement have installed controls since the last time a RACT emission limit was approved into the applicable SIP, the RACT determination basically is a determination if any additional level of control beyond that in the settlement agreement is reasonably available for the source in question. This determination will clearly be a highly source-specific determination which will depend upon the specific requirements of the consent agreement and the characteristics of the emissions units involved. In the case of a conclusion that no additional level of control is RACT then RACT for such source needs to reflect the particulars of the settlement agreement and be set as an emission limit (typically one that is rate based such as mass of pollutant per unit of production or mass of VOC per volume or mass of coating or coating solids applied or one expressed as an overall percentage of emission reduction) with an averaging period appropriate to protect the ozone standard and consistent with emissions measuring/testing and monitoring techniques.

Given the definition of RACT as the lowest emission limit a source is capable of meeting by application of reasonably available technology that is technically and economically feasible, EPA expects Pennsylvania's proposed NOx RACT limits to reflect the "lowest emission limit" sources are capable of achieving with technically and economically feasible controls.

II. Comments

A. Regarding Proposed Section 129.97 and Large Sources Currently equipped with Advanced Controls:

As discussed above, the Board and the Pennsylvania Department of Environmental Protection (PA DEP)[2] cannot presumptively assume that the reductions obtained through compliance with the ozone season and annual NOx emissions caps under the NOx SIP Call or the CAIR are at least equivalent to what would be achieved if RACT requirements were applied on a source-specific basis; however, the actual emissions rates achieved in practice by those sources subject to the NOx SIP Call or the CAIR requirements in the past few years would be relevant "other information available" for making RACT determinations. Because RACT for an individual source must consider the technological and economic circumstances of that individual source, RACT for those sources subject to the CAIR (and/or NOx SIP Call) that installed NOx reduction controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) post-combustion controls must consider the actual emissions levels achieved in practice while operating those controls. Those emission rates achieved in practice clearly demonstrate that SCR or SNCR are presumptively technologically feasible at that individual source. Many of the currently in-place SCR and SNCR were installed in response to the NOx SIP Call, the CAIR and similar rules pursuant to prior ozone standards. Under a regional cap-and-trade regime, EPA set the emissions caps based upon what emissions reductions could be achieved in a highly cost-effective manner, that is, through the installation of highly cost-effective controls. See, for example, 70 FR 25162 at 25198-25-25199, May 12, 2005, discussing the regulatory background of the NOx SIP Call, and, see 70 FR 25162 at 25199-25201 and 25205-25215 for EPA's analysis of the cost effectiveness of the CAIR considering both average and marginal costs. The CAIR set a first phase of NOx reductions starting in 2009 (covering 2009–2014) and a second phase of NOx reductions starting in 2015 (covering 2015 and thereafter). EPA believes that actual emission data reported to EPA's Air Markets Program Database (AMPD) for EGUs through

[2] Hereafter whenever EPA uses the terms "PA DEP" or Pennsylvania we mean the PA DEP and the Board individually or collectively as applicable in their roles of adopting final rules.

2013 will be reflective of those controls installed in response to the NOx SIP Call and the CAIR. EPA believes, absent information to the contrary, that a starting point for RACT determinations associated with the 2008 ozone NAAQS for the EGUs and other large units equipped with SCR, SNCR and similar NOx controls already in-place is that such controls should be considered highly-cost effective given EPA analysis for the NOx SIP Call and the CAIR provisions.

Attachment A is a preliminary summary of emissions-related data for 2013 and many prior years extracted by EPA Regional Office Staff from EPA's AMPD of many coal-fired EGU boilers in Pennsylvania equipped with SCR or SNCR. Included in Attachment A is the facility name, the unit identification number, the data year, the average NOx emission rate (Avg NOx Rate in lb/MMBtu[3]), the NOx emissions (in tons), the operating hours, the heat input (in millions of BTU, i.e. mmBTU), the number of months reported for that year (the data is for the ozone season), the NOx controls in place and other data. The data is that reported to the AMPD except the average NOx emission rate which is that returned from the AMPD and which is averaged over the 5 month period. EPA notes that the average NOx emission rate is an average over the entire reporting period, the significance of the averaging period will be discussed in a following paragraph. Attachment B is selected data excerpted from Attachment A. The average emission rates have been excerpted for 2013 (or the most recent year available), for 2011 and for the first full year after installation of SCR, SNCR or ammonia injection controls. Generally, this data shows that the average emission rate in more recent years is higher than the emission rate in years after the implementation of the NOx SIP Call in 2004. (We can provide copies of Attachments A and B as Excel® files upon request.)

The average emission rate data shows that in the past the SCR-equipped units were capable of much lower emission rates than those proposed by the Board on April 19, 2014. The proposed emission rates in most cases (Montour Units 1 and 2 excepted) are far higher than the most recent (2013 ozone season) emission rates for units equipped with SCR and are higher than the emission rates achieved over the 2011 ozone season (Keystone Units 1 and 2 excepted). 2011 is significant because EPA proposed 2011 as the presumptive RFP planning baseline year for the 2008 ozone NAAQS. The emission limits proposed on April 19, 2014 are far higher (by a factor of 4.5 to over 8) than the best ozone season data on record. EPA finds this data significant as RACT should be set at the lowest emission level with technically and economically feasible controls.

For the tangentially fired EGUs, the average NOx emission rate for the best performing year is over seven times less (Cheswick Unit 1 excepted) than the emission rate proposed on April 19, 2014. Except for Cheswick Unit 1 (with a 2011 average rate of 0.239 pounds NOx per mmBTU versus the proposed 0.35), the proposed rates are essentially equal to the 2011 average rates; compared to 2013 data, Keystone Units 1 and 2 had average emission rates around one-

[3] lb/MMBtu or /mmBTU is an abbreviation for pounds per million British Thermal Units.

half of the proposed emission rate of 0.35 pounds NOx per mmBTU while for Montour Units 1 and 2, the proposed emission rates would force a reduction from 2013 levels. Cheswick Unit 1 in 2013 would have met the proposed emission rate with a compliance margin of around 7%.

The proposed emission rates for dry bottom wall-fired, EGU boilers are much higher than the average rates achieved in 2011 and 2013 and roughly 4.5 to almost 6 times higher than the lowest rates achieved in the best year. For these EGU boilers equipped with SCR the AMPD data for 2011 and 2013 indicates that the proposed emissions rates require re-evaluation because in one or both of these years each unit was able to achieve an average emission rate better than that proposed on April 19, 2014. The AMPD data for the best year suggests that these units are capable of far lower emission rates than those proposed on April 19, 2014.

For the EGUs equipped with SNCR, the actual average historical emission rates are not as far below the proposed emissions limits (or in some instances above the proposed rates) as is the case for units equipped with SCR: For tangentially-fired, cell burner and dry bottom vertically-fired boilers, the proposed rates generally are not much greater than the best actual average rates and will result in reductions from 2011 and 2013 levels. For the dry bottom wall-fired boilers at the Shawville plant the same is true. For the same type of units at the New Castle plant, since installation of SNCR, the actual average emission rates at Units 3 and 4 have always been well less than the proposed 0.40 pounds NOx per mmBTU. In the case of Unit 5, the historical actual average emission rates between 2006 and 2009 (inclusive) and 2013 have been lower than the proposed emission limit while for 2010 through 2012 the historical actual average emission rates have been higher than the proposed rate. For EGUs with SNCR installed, PA DEP should explain how historically achieved lower NOx emission rates at such units is not technically or economically feasible for RACT.

For dry bottom wall-fired boilers with SNCR at the cogeneration facilities the proposed emission rate of 0.40 pounds of NOx per mmBTU input will force reductions from 2011 and 2013 levels. In general, the historical actual average ozone season emission rates do not present a compelling case that a lower emission rate has been proven to be technologically feasible for all four units. Only one unit of four has had any emission rates averaged over an ozone season less than the proposed 0.40 emission limit.

However, the data for circulating fluidized bed boilers at small power producers and pulp mills (P. H. Glatfelter Company, Panther Creek Energy Facility, Piney Creek Power Plant and Scrubgrass Generating Plant) suggest that the facilities listed on Attachments A and B are capable of achieving emission rates well below the proposed emission limit of 0.20 pounds NOx per million Btu heat input. For Panther Creek Energy Facility, the highest actual ozone season average emission rate was 0.136 lb NOx/mmBTU (Unit 1, 2010). For Piney Creek Power Plant the highest actual ozone season average emission rate was 0.160 pounds NOx/ mmBTU with many years below 0.142. For the Scrubgrass Generating Plant, no actual ozone season average emission rate exceeded 0.151 pounds NOx/ mmBTU. Therefore, for circulating fluidized bed boilers at small power producers and pulp & paper mills, PA DEP should explain how historically achieved lower NOx emission rates at such units is not technically or economically feasible for RACT.

Further, the NOx caps imposed by the regulation(s) issued in response to the CAIR applicable to sources in Pennsylvania include annual and ozone season mass caps. Because compliance with the current ozone NAAQS is determined over an 8-hour period, EPA recommends RACT emission standards for the ozone NAAQS to be based ***upon a short-term basis*** such as daily or 24-hour rolling average basis even though we have previously approved 30-day rolling averages, that is not our current recommendation and we don't think it is appropriate for current RACT. The average emission rates shown on Attachments A and B are averaged over the entire ozone season which is consistent with the ozone season cap and allowance trading regimes set up by the NOx SIP Call and the CAIR; however, EPA believes shorter-term averaging is appropriate for RACT and any proposal for RACT from Pennsylvania should include this consideration.

The actual historical emission rates in Attachment A are relatively long-term (153 day) averages and thus cover a wide variety of operating conditions – periods of steady state operation, periods of varying loads, catalyst bed temperatures (or in the case of SNCR temperatures at reducing reagent injection sites), combustion gas flow rates and fuel input, and control system degradation between routine maintenance activities and catalyst deactivation between periodic catalyst replacement. Therefore, EPA believes a shorter term a shorter term (30-day rolling or less) RACT emission rate can include a reasonable compliance margin to account for such common variations in performance due to technological limitations of the control systems. EPA would expect that the numerical value of a 30-day rolling average emission limit would be less than that for a 24-hour rolling period because over a 30-day period the source can average longer periods of steady state operation off against periods of varying loads and can to some extent react to periods of higher emission rates by optimizing the controls.

Summary and Comments:

In short, EPA believes that the RACT emission rates proposed on April 19, 2014 for those coal-fired boilers currently equipped with SCR listed in Attachments A and B are not appropriately justified as RACT. EPA believes Pennsylvania would need compelling technical and economic supporting documentation that 0.35 pounds NOx/mmBTU input is an appropriate RACT-based limit for units that have achieved lower emission rates in the past as demonstrated by data from EPA's AMPD database. For example, EPA directs attention to emissions data from Cheswick Unit 1; Keystone Units 1 and 2, Montour Units 1 and 2, Bruce Mansfield Units 1, 2 and 3, Homer City Units 1, 2, and 3, and New Castle Units 3 and 4. The APMD data clearly shows that lower emission limits for these units appear to be technologically feasible. EPA continues to evaluate whether such controls are economically feasible and will review Pennsylvania's analysis when submitted.

Each of these units mentioned above has been able to achieve far lower emission rates in the past (albeit over a longer averaging period than a 30-day rolling) and thus the technological feasibility of lower emission rates than those proposed on April 19, 2014 appears to have been demonstrated from this past performance. Generally, EPA believes that the RACT emission rate for wall fired units (with SCR) must be lower because these units generally achieved much lower emission rates during 2011 and later years and have shown the ability to achieve even lower emission rates prior to 2011. For tangentially-fired boilers equipped with SCR, each facility's data presents a similar story though trends vary from facility-to-facility. For example, emission units at Cheswick, Keystone, and Montour have all demonstrated an ability to emit NOx at levels far below the proposed NOx RACT limits particularly with data prior to 2011. Absent a detailed analysis of the incremental costs to achieve lower emission rates than the average rates achieved in 2011 through 2013 to support economic infeasibility, EPA does not believe that Pennsylvania has adequately demonstrated that the proposed emission rates are RACT. Given the variability of performance between facilities and in some cases between units within the same facility, PA DEP could set RACT emissions limits for these units either (1) on a facility-by-facility basis or even a unit-by-unit basis, or (2) use more subcategories for which one limit would be RACT such as a limit to cover "electric utility - coal-fired, tangentially fired with SCR installed before certain date," another emission limit to cover "electric utility - dry bottom wall-fired boiler with SCR installed before certain date," an emission limit to cover "cogeneration - dry bottom wall-fired boiler with SNCR installed before a certain date," and separate limits for newer installations.

For the electric utility (not cogeneration or circulating fluidized bed boilers (CFBs)) units equipped with SNCR, PA DEP should provide an explanation for why RACT does not reflect prior performance levels lower than what is proposed where relevant. In summary, for these units equipped with SNCR, EPA believes that PA DEP will need to provide adequate justification of why the RACT limits should not be reflective of the best performing year's rates from units with SNCR based on technical and economic feasibility.

Likewise, for the small power producers and pulp & paper mills (P. H. Glatfelter Company, Panther Creek Energy Facility, Piney Creek Power Plant and Scrubgrass Generating Plant), EPA believes that PA DEP must provide an adequate technical and economic justification for the proposed 0.20 pounds NOx per million Btu heat input emission rate as RACT as these sources appear to be technically capable of meeting, on a short-term basis with a reasonable compliance margin, lower limits. In addition, PA DEP should explain, as discussed above, for these sources why the proposed 0.20 pounds NOx per million Btu heat input emission rate should not be set with a 24-hour rolling averaging period for those sources equipped with CEMS. Such RACT can be set for each facility or on a unit-by-unit basis or by relevant subcategory if one emission limit is RACT for such a subcategory.

Enclosure 2: EPA Comments on Proposed Amendments to Chapters 121 and 129 Presumptive Reasonably Available Control Technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NOx) and volatile organic compound (VOC) emissions. [44 Pa.B. 2392, April 19, 2014]

EPA also believes that SCR must be evaluated as RACT for all coal-fired EGU combustion units (except those already equipped with SCR) given that many nearby states have imposed limits in the 0.12 to 0.15 pounds NOx per million Btu heat input for coal fired EGU (or very large boilers) averaged over a 24-hour period. Refer to New Jersey N.J.A.C. 7:27-19.4 for limits to take effect May 1, 2015, Delaware Regulation 1146 (Title 7 of Delaware's Administrative Code) which were effective January 1, 2012 and New York's 6 NYCRR Part 227, Subpart 227-2 to take effect on July 1, 2014. (More discussion of other States' current regulations is included in Section II. B. below.) These other states' NOx limits are likely consistent with use of SCR control technology. Such RACT evaluation for installation and operation of SCR must consider technological feasibility, emission reductions and cost effectiveness. EPA recognizes that the potential emission reductions from those units currently equipped with SNCR or ammonia injections will be determined from a baseline emission rate reflective of the controls in place.

EPA is aware that many factors will impact PA DEP's evaluation of economic feasibility for RACT such as expected life of sources, but any such evaluation should be documented

B. Other State Rules

As discussed in the background (Section I above), EPA has advised that when updating their RACT rules States need to consider more recent technical information available in other forms, such as the *SIPs for other nonattainment areas*. EPA Region III staff have compiled information concerning NOx limits in the SIPs for several nearby States. Staff looked mainly at Delaware, New Jersey, New York, and Maryland for the following reasons: The entire Commonwealth is in the OTR like these four States and shares borders with these States; the Commonwealth shares one ozone nonattainment area – the Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE area under both the 1997 and 2008 ozone NAAQS with Delaware, Maryland and New Jersey. The Commonwealth like New York has a heavily urbanized area along the "Interstate 95 Corridor" and has a mix of smaller urban areas and rural areas distributed throughout the remainder of the State.

Attachments C and D provide this summary. (We can provide copies of Attachments C and D as Excel® files upon request.) This compilation compares the NOx limits in the SIPs with those in the current PA SIP (excluding source specific limits previously determined under sections 129.91-129.95) and with those proposed on April 19, 2014. This compilation is not necessarily comprehensive, but is provided for comparison purposes reflecting EPA's summary of provisions.

Of these other States' limits a comparison of limits from New Jersey and New York regulations are compared side-by-side on Attachment D (as far as a comparison is possible given that certain limits are expressed in different form such as pounds NOx per mmBTU versus pounds NOx per Megawatt output or versus ppmvd NOx)[4]. New Jersey and New York were selected because these two States have revised their NOx emission limits more recently than others and have more stringent limits to take effect during 2014 or 2015. Some of these rules may have been adopted to attain the 1997 8-hour ozone NAAQS and/or updated prior rules which were over a decade old and did not reflect advancements in technology that are currently reasonably available.

EPA believes that the PA DEP should review all the limits on Attachments C and D when evaluating technological and economic feasibility of RACT for the identified source categories. In particular, PA DEP should consider those limits which have been in effect for several years or those limits which apply to new or modified sources installed after a specified date. If some lower limit than those proposed on April 19, 2014 are determined to be RACT, PA DEP should revise its limits for those categories (or subcategories) or otherwise justify the current limits on the basis of economic and technologically feasible options and potential emission reductions, (or provide a negative declaration for source types which do not exist in PA that are regulated in other States). With this comment, EPA is not stating that these other limits are presumptively RACT for sources in the Commonwealth but rather need to be considered and evaluated.

The following are some examples:

EPA directs Pennsylvania's attention to New Jersey's emission limits rates on for coal fired EGU boilers are 1.5 pounds NOx/MW-hour output (we understand that the equivalent rate in pounds NOx/mmBTU input is 0.15 based upon a conversion factor of 10,000 mmBTU/kW output or 10 mmBTU/MW output). EPA also directs attention to New York's allowable emission rate for coal fired, "very large boilers" (> 250 mmBTU/hour input and likely most New York EGU boilers) which will fall to 0.12 pounds NOx/mmBTU as of July 1 of 2014.

EPA also suggests Pennsylvania consider for technological and economic feasibility for RACT that New York has adopted limits for coal-fueled, fluidized bed combustion units over 250 mmBTU/hour input of 0.08 NOx/mmBTU versus the proposed 0.20 NOx/mmBTU. EPA recommends that PA DEP evaluate the feasibility of additional controls for this category; EPA recognizes that the technical and economic feasibility will be affected by the existence of existing controls because potential emission reductions from those units currently equipped with SNCR or ammonia injection can be determined from a baseline emission rate reflective of the controls in place.

Also, New Jersey has adopted a lower presumptive emission limit for municipal solid waste incinerators/combustors (MSWC) of 150 ppmvd (corrected to 7% O2) NOx. The 40 CFR

[4] The abbreviation "ppmvd" stands for parts per million dry basis.

Part 60 limits proposed on April 19, 2014 for MSWCs constructed on or before September 20, 1994, vary from 205 to 250 ppmvd (corrected to 7% O2) NOx except for fluidized bed combustors for which the limit is 180 ppmvd (corrected to 7% O2). EPA notes that Connecticut's MSWC regulation sets lower limits for mass burn waterwall MSWCs constructed after December 20, 1985 but before September 20, 1994 of around 177 ppmvd (corrected to 7% O2).[5] EPA believes that PA DEP should evaluate these lower limits and should evaluate the 150 ppmvd (corrected to 7% O2) to see if it is RACT for all MSWCs, adopt lower limits for categories where lower limits are RACT or otherwise justify the current limits on the basis of economic and technologically feasible options and potential emission reductions.

C. Cost-Effectiveness Threshold:

In the "Regulatory Analysis Form"[6] (RFA) for the April 19, 2014 proposed rule a cost effectiveness "benchmark" of $2,500 per ton of NOx reduced was used apparently as a maximum cost effectiveness cut-off: "Using these benchmarks, the Department projects that the cost of complying with the applicable presumptive RACT requirement or RACT emission limitation by installing add-on control technology or by complying through an averaging protocol would be less than $2,500.00 maximum per ton of NO_x emission reductions, no matter which source type and add-on control technology is considered." (Refer to RFA Section (19) "(19) Provide a specific estimate of the costs and/or savings to the **regulated community** associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived," on page 20.) While EPA concurs that $1,500.00 in 1990 dollars is essentially equivalent to $2,500.00 in 2010 dollars[7] and that EPA approved (75 FR 64155, October 19, 2010) Wisconsin's RACT rule which used a $2,500 per ton cost effectiveness threshold EPA notes that there are several differences between Wisconsin's situation and the Commonwealth's.

First, Wisconsin was required to adopt NO_X RACT rules for the 1997 8-hour ozone standard (75 FR 64155 at 64156, October 19, 2010) and submitted the rules approved on October 19, 2010 for that purpose. EPA interprets Pennsylvania's April 19, 2014 proposed rule to be all or part of a revision to Pennsylvania's SIP to address the RACT requirements under both the 1997 and 2008 ozone NAAQS.

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[5] A copy can be accessed on-line at http://www.epa.gov/region1/topics/air/sips/ct/CT_22a_174_38.pdf

[6] http://files.dep.state.pa.us/PublicParticipation/Public%20Participation%20Center/PubPartCenterPortalFiles/Environmental%20Quality%20Board/2013/November%2019%20EQB/RACT%20Requirements/RACT2%20PRN%20RAF.pdf

[7] EPA used the "CPI inflation calculator" available at http://www.bls.gov/data/inflation_calculator.htm from the U.S. Department of Labor, Bureau of Labor Statistics (BLS).

Next, Wisconsin adjusted the $1,300/ton figure from EPA's March 16, 1994, memorandum, "Cost-Effective Nitrogen Oxides (NOx) Reasonably Available Control Technology (RACT)'" from E. Kent Berry, Acting Director of EPA's Air Quality Management Division and grew this out to the 2005 equivalent of roughly $2,000/ton using the consumer price index. Wisconsin *then* took the additional step to increase the reasonable cost-effectiveness of controls upwards to $2,500/ton for evaluating RACT based on several considerations. Thus, arguably, Wisconsin adjusted the *2005*-dollar equivalent value of $2,000.00 upwards by 25% to arrive at its $2,500 per ton value. Pennsylvania's $2,500 per ton benchmark is in 2010 dollars.

Because Pennsylvania may use these proposed rules for 2008 ozone NAAQS RACT, EPA believes that to reach a somewhat more equivalent situation to Wisconsin, Pennsylvania should adjust its benchmark out to 2012 or later dollars to better address the 2008 ozone NAAQS. Using the BLS "CPI inflation calculator" to adjust $1,500 in 1990 dollars to 2012 dollars will yield $2,530 (rounded to the nearest 10 dollars). Adjusting this upwards by 25% will yield $3,160 in 2012 dollars.[8]

EPA further notes that Wisconsin adopted much lower emissions limits for solid fuel fired boilers[9] than the limits for coal fired boilers and combustion units[10] proposed on April 19, 2014 even with a $2,500 per ton cost effectiveness.

EPA notes that other nearby States have adopted recent NOx RACT limits with far higher average cost effectiveness than $2,500 per ton. For instance, New York State estimated that proposed NOx limits to take effect in 2015 would have an average cost effectiveness ranging from $2,600 to $5,463 per ton (Proposed revisions to Subpart 227-2 published in the NYS Register on December 23, 2009)[11]. New York State Department of Environmental Conservation (NY DEC) started with a higher cost effectiveness threshold for NOx RACT of $3,000 per ton (1994 dollars) over which an "emission source of VOC or NOx will not be required to implement any emission reduction or control strategy that is more costly than the established

[8] Applying the same procedure to adjust to 2014 dollars will yield $3,275 per ton.

[9] These were between 0.10 and 0.25 pounds of NOx per mmBTU input (75 FR 14116 at 14119, March 24, 2010). Full details of the Wisconsin submittal can be found on-line at www.regulations.gov in Docket EPA-R05-OAR-2007-0587. These limits were to be averaged on a 30-day rolling basis.

[10] These were 0.35 to 0.45 pounds of NOx per mmBTU input in general and 0.20 pounds of NOx per mmBTU input for CFBs.

[11] A copy of New York's proposed rule is docketed at www.regulations.gov as an attachment to document EPA-R02-OAR-2013-0180-0004 in docket EPA-R02-OAR-2013-0180.

threshold adjusted over time for inflation."[12] Using the BLS "CPI inflation calculator" NY DEC determined that $3,000.00 dollars in 1994 equates to $4,638 dollars in 2012, which was then rounded up to $5,000 to ensure a level of conservatism.[13]

New York State's approach would seem to be more in line with EPA's March 16, 1994 guidance and policy which said: "In determining the NOx RACT comparable cost-effectiveness level, EPA believes that it is appropriate to focus on the range of cost effectiveness. The range is appropriate due to the variability of the actual cost effectiveness that is expected from unit to unit. Therefore, NOx technologies with a cost-effectiveness range that overlaps the $160 to $1300 range should, at a minimum, be considered by States in the development of their NOx RACT requirements." New York did not exclude consideration of controls even when this $5,000 per ton threshold was exceeded by over $450 in some cases. Pennsylvania appears to be excluding any consideration of controls if the average cost-effectiveness is over $2,500 per ton instead of considering those controls cost effectiveness range includes $2,500 per ton. Therefore, EPA believes Pennsylvania needs to appropriately explain its cost-effectiveness calculations.

EPA has stated that a rigid coat effectiveness benchmark should not be used to exclude consideration of controls without considering other factors. EPA stated in its March 16, 1994 guidance[14] that while cost effectiveness, as described above, is an important consideration, it must be noted that other factors should be integrated into a RACT analysis. For example, emission reductions and environmental impact should be considered. EPA also stated that in addition, since EPA's 1994 presumptive RACT levels for utility boilers were expected to be met by a majority of (but not all) sources, States should expect some sources to experience higher cost-effectiveness levels in order to meet the NOx RACT requirements.

EPA therefore strongly cautions PA DEP not to rigidly apply a benchmark as low as $2,500 per ton to exclude consideration of technically feasible controls. Rather, Pennsylvania needs to consider a broader range of cost effectiveness to see if some level of additional control falls within that range. Based on Wisconsin's analysis, PA DEP should consider raising its cost-

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[12] DAR-20: Economic and Technical Analysis for Reasonably Available Control Technology (RACT) Networks, Effective October 18, 2013, available on-line at http://www.dec.ny.gov/chemical/91851.html. Applying the BLS "CPI inflation calculator" to adjust $3,000 in 1994 dollars to 1990 dollars will yield $2,645 per ton. Also, $1,500 in 1990 dollars is equivalent to $1,700 in 1994 dollars.

[13] *Id.*

[14] Memorandum from D. Kent Berry, Acting Director, Air Quality Management Division "Cost-Effective Nitrogen Oxides (NOx) Reasonably Available Control Technology (RACT)," dated March 16, 1994, available on-line at http://www.epa.gov/ttn/oarpg/t1/memoranda/costcon.pdf.

effectiveness "benchmark" like Wisconsin and New York after considering and evaluating thoroughly the states' analysis mentioned above.

D. Regarding Averaging Provisions of Proposed Section 129.98:

EPA has a significant concern regarding proposed section 129.98. "Facility-wide or system-wide NOx emissions averaging RACT operating permit modification general requirements." As mentioned previously, the United States Court of Appeals for the D.C. Circuit remanded that portion of the November 29, 2005 Phase 2 rule to EPA concerning the presumption that regional cap and trade programs satisfy RACT requirements without any showing or demonstration that such programs achieve emissions levels which can be achieved if RACT emission limits were imposed upon each source in the area required to implement RACT under subpart 2 (CAA sections 181 to 185B). In the June 6, 2013 proposed rule EPA reiterated its position that RACT level emissions reductions can be demonstrated on an area-wide averaging basis (78 FR 34178). As noted previously the RACT requirement is applicable to all of the Commonwealth under CAA section 184 (SIP requirements for areas in the OTR). The RACT requirement also applies to any ozone nonattainment area classified as Moderate or higher (Serious, Severe or Extreme) under CAA sections 172(c)(1) and 182(b)(2). Currently under the 2008 ozone NAAQS, no ozone nonattainment area in the Commonwealth is classified as Moderate or higher. However, under the 1997 ozone NAAQS there are two areas classified as Moderate nonattainment: these are the Pennsylvania portion of the Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE area and Pittsburgh-Beaver Valley, PA area (hereafter the Philadelphia and Pittsburgh areas). In the June 6, 2013 proposed SIP Requirements Rule for transition from the 1997 ozone NAAQS to the 2008 ozone NAAQS, EPA proposed to revoke the 1997 ozone NAAQS with promulgation of sufficient anti-backsliding rules. The proposed anti-backsliding rule sections 51.1105(a)(1) and 1100(o) would require fulfillment and retention of RACT rules required under the 1997 ozone and earlier ozone NAAQS in areas classified as Moderate or higher nonattainment in areas designated nonattainment for the 2008 ozone NAAQS. *See* 78 FR 34178 at 34234-34235. (In the absence of a revocation of the 1997 ozone NAAQS, the RACT requirement for the Moderate ozone nonattainment areas under the 1997 ozone NAAQS would continue to apply until moved to the contingency provisions of a maintenance plan under CAA section 175A. Likewise, the OTR RACT requirement remains applicable <u>on separate and independent basis</u> throughout the Commonwealth unless the Commonwealth or portions thereof are removed from the OTR pursuant to CAA section 176A.) Therefore, RACT remains an applicable requirement under the 1997 ozone NAAQS in the Philadelphia and Pittsburgh areas due to their designation and classification as Moderate ozone nonattainment areas.

Enclosure 2: EPA Comments on Proposed Amendments to Chapters 121 and 129 Presumptive Reasonably Available Control Technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NOx) and volatile organic compound (VOC) emissions. [44 Pa.B. 2392, April 19, 2014]

The decision in *NRDC v. EPA*, 571 F.3d 1245 (D.C. Cir. 2009) stands for the proposition that a demonstration that *any* alternative to imposing RACT emission limits on each major stationary source must demonstrate at a minimum the alternative achieves at least the level of reductions within the nonattainment area that would occur if RACT emission limits were imposed on each source. In the preamble to the June 6, 2013 proposed SIP Requirements Rule (78 FR 34178 at 34193), EPA noted that the Court emphasized that the CAA calls for RACT-level reductions in each area subject to RACT requirements: "The court held that '[b]ecause the EPA has not shown that the NOx SIP Call compliance will result in at least RACT-level reductions in emissions from sources within each nonattainment area, the EPA's determination that compliance with the NOx SIP Call satisfies the RACT requirement is inconsistent with the 'in the area' requirement and thus violates the plain text of [section] 172 (c)(1)." Additionally, the court emphasized that "the RACT requirement calls for reductions in emissions from sources in the area; reductions from sources outside the nonattainment area do not satisfy the requirement." In the June 9, 2014 proposed rule (79 FR 32892 at 32896), EPA reiterated this interpretation that the "Court specifically held that the Phase 2 Ozone Implementation Rule allowing use of the NOx SIP Call to constitute RACT without any locally applicable analysis regarding the equivalence of NOx SIP Call and RACT reductions: 'is inconsistent with the Clean Air Act . . . in allowing participation in a regional cap-and-trade program to satisfy an area-specific statutory mandate.' The Court emphasized that: 'the RACT requirement calls for reductions in emissions from sources in the area; reductions from sources outside the nonattainment area do not satisfy the requirement . . . Accordingly, participation in the NOx SIP Call would constitute RACT only if participation entailed at least RACT-level reductions in emissions from sources within the nonattainment area." EPA believes that the Court's logic regarding regional cap-and-trade programs and RACT applies equally to other sorts of trading and averaging programs.

EPA believes that, as proposed, section 129.98 does not meet the Court's ruling in *NRDC v. EPA* and therefore would not be approvable because it contains no provisions that ensure at least RACT-level reductions always occur within a nonattainment area required to implement RACT as the Philadelphia and Pittsburgh areas are required to do under the 1997 ozone NAAQS. As presently proposed, section 129.98 does not prevent reductions outside the Philadelphia or Pittsburgh area from offsetting less-than-RACT level reductions within either of the two nonattainment area's boundary. Pennsylvania would need to demonstrate any facility-wide averaging or system-wide averaging results in reductions within a specific nonattainment area. Unless Pennsylvania can justify compliance with the D.C. Circuit's directive that reductions must occur within the nonattainment area for Section 129.98, EPA suggests the proposed regulation must be revised to not include averaging as a compliance option, must be revised to restrict averaging alternatives so emissions units inside the Philadelphia area or the Pittsburgh area average solely with other emissions units within the same nonattainment area boundary, or must be revised to include other provisions demonstrating at least RACT-level reductions in emissions from sources within the nonattainment area through continuous compliance (along with appropriate enforcement and penalty provisions.

Enclosure 2: EPA Comments on Proposed Amendments to Chapters 121 and 129 Presumptive Reasonably Available Control Technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NOx) and volatile organic compound (VOC) emissions. [44 Pa.B. 2392, April 19, 2014]

In evaluating the proposed RACT averaging provision in Section 129.98, EPA also cautions that Pennsylvania should consider potential future reclassification of certain areas not presently attaining the ozone NAAQS to Moderate or higher nonattainment classification status. In general, to assure compliance with the D.C. Circuit's holding in *NRDC v. EPA*, Pennsylvania should consider restricting any emissions averaging to averaging among units within the same specific nonattainment area.

E. Implementation/Permitting Comments:

Section 129.100 sets forth the criteria for all sources – those subject to the presumptive RACT, those included in facility-wide or system-wide NOx emissions averaging, and those covered by an Alternative RACT proposal – for demonstrating compliance with RACT NOx and/or VOC limits. All RACT limits and associated monitoring would be applicable requirements in Pennsylvania Title V permits where a source is subject to RACT. Title V permits must include periodic monitoring that is sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit [see 25 Pa. Code § 127.511 for example]. Section 129.100(a)(2) of the proposed RACT rule provides that a facility subject to a NOx and/or VOC emissions limit that does not operate a CEMs may "demonstrate compliance with a PA DEP-approved source test." EPA recommends Pennsylvania consider requiring more than one stack test. EPA suggests that the RACT rule should require that each RACT permit shall include periodic monitoring that is sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit. Even with a more frequent source test, additional monitoring such as direct monitoring of NOx and VOCs, parametric monitoring where controls are in place, etc., may be required to assure compliance at all times.

Facility-wide or system-wide NOx emissions averaging is proposed as an option for affected facilities that cannot meet the applicable NOx RACT requirement or limit. Facility-wide monitoring is even more complex (and thus more difficult to permit and to demonstrate compliance) than unit-specific monitoring, as exemplified by the NSR Plant-wide applicability limit (PAL) rules. A permit issued by PA DEP pursuant to §129.98(i) should specify that "each air contamination source" at a Title V facility includes all NOx emitting sources at the facility, including insignificant sources if they have a potential to emit NOx, and other units that emit NOx at rates lower than *de minimis* levels set forth in §129.97. The proposed rules only require air contamination sources to be listed in the permit modification submitted by the owner/operator. Each air contamination source and its potential to emit should be included in the NOx emissions averaging RACT operating permit for clarity.

In proposed section 129.98(e), the daily actual NOx emission rate for air contamination source i, (Ri_{actual}) must include emissions from start and shut downs, that is, the definition of

Enclosure 2: EPA Comments on Proposed Amendments to Chapters 121 and 129 Presumptive Reasonably Available Control Technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NOx) and volatile organic compound (VOC) emissions. [44 Pa.B. 2392, April 19, 2014]

Ri_{actual} should be changed to read: "Ri_{actual} = The daily actual NOx emission rate <u>including emissions during start-ups and shut-downs</u> for air contamination source i, lb/mmbtu, using a 30-day rolling average." (next text underlined)

EPA cautions Pennsylvania that it should consider addressing in its regulations permissible changes to sources with facility-wide caps or requirements for sources to follow when seeking modifications if subject to facility wide caps.

The rule should require that records described in §129.100(e) through (i) be maintained for 5 years and be made available to PA DEP or appropriate air pollution control agencies upon request.

Proposed section §129.98(b) refers to an "operating permit modification" that has two interpretations, as proposed: that which is submitted by the owner or operator and that which is issued by PA DEP. Neither use comports with the definition of "modification" in existing section 121. At a minimum, the word "application" or "proposal" should be added after "modification" wherever this section refers to that document which is submitted by the owner or operator.

Language in proposed section 129.98(m) should be changed to state that an operating <u>permit</u> would be violated, not an operating permit <u>modification</u>.

F. Regarding Proposed Section 129.97(g)(vi)(C):

EPA recommends that this provision be modified to substitute the words "any other" for "another" read as follows:

"(C) <u>Any other</u> combustion unit, 0.40 pounds NOx/million Btu heat input."

The word "another" generally means "extra, additional" whereas "another" generally means "some other" thus better conveying in context "some other type of combustion unit" or "all other types."

III. Data Sources Used for Other State Rules

1. For Current SIP Regulatory Text – Compilations of the currently approved SIPs go to:

<u>http://www.epa.gov/region2/air/sip/</u> and work one's way through the different organizational methods branching, drop-down structures. For Region 2 go to: <u>http://www.epa.gov/region02/air/sip/summary.htm</u>.

Enclosure 2: EPA Comments on Proposed Amendments to Chapters 121 and 129 Presumptive Reasonably Available Control Technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NOx) and volatile organic compound (VOC) emissions. [44 Pa.B. 2392, April 19, 2014]

For Region 3 go to: http://yosemite.epa.gov/r3/r3sips.nsf/SIPIndex!OpenForm.

2. Another source is State web sites.

CAUTION: Rules on State sites are usually the current rules in effect at the state level and are not necessarily the version approved into the SIP.

a. OTR States:

New Jersey: http://www.state.nj.us/dep/aqm/rules.html "Rules Currently in Effect New Jersey Administrative Code Title 7, Chapters 27, 27A, 27B and 27C:" In particular at http://www.state.nj.us/dep/aqm/rules27.html Title 7, Chapter 27, Air Pollution Control N.J.A.C. 7:27-1 through 34: Subchapter 16 "Control and Prohibition of Air Pollution by Volatile Organic Compounds (7:27-16.01 through 7:27-16.27, revisions through September 6, 2011)" and subchapter 19 "Control and Prohibition of Air Pollution by Oxides of Nitrogen (7:27-19.1 through 7:27-19.30, revisions through September 6, 2011)."

http://www.state.nj.us/dep/aqm/1997adop.html "Amendments to N.J.A.C. 7:27, 27A, 27B and 27C adopted since 1997." Refer particularly to rules adopted under "Ozone RACT - New rules and amendments for 14 source categories," "Oxides of Nitrogen (NOx)"

http://www.state.nj.us/dep/aqm/curformp.html "Includes rule proposals that were published or submitted for publication in the New Jersey Register and are still open for public comment. Also includes proposals for which the comment period has closed or that the Department has either adopted or allowed to expire since 2002." Refer to particularly to rules under "Ozone RACT - Proposed new rules and amendments for 13 source categories," and "Control and Prohibition of Air Pollution from Oxides of Nitrogen (NOx), including provisions on distributed generation." (Rules listed herein may be the proposal for one or more adopted rules listed at http://www.state.nj.us/dep/aqm/1997adop.html and http://www.state.nj.us/dep/aqm/rules27.html above.

Delaware: Current Regulations can be found at http://regulations.delaware.gov/AdminCode/title7/1000/1100/index.shtml#TopOfPage.

Maryland: http://www.dsd.state.md.us/comar/subtitle_chapters/Titles.aspx & pick the Title 26 in the drop-down box "SELECT BY TITLE NUMBER" to get to: http://www.dsd.state.md.us/comar/subtitle_chapters/26_Chapters.aspx click on "11 AIR

QUALITY" to get to:
http://www.dsd.state.md.us/comar/subtitle_chapters/26_Chapters.aspx#Subtitle11.

Pennsylvania: PA regulations can be found at http://www.pacode.com/secure/data/025/articleICIII_toc.html. See also the proposed rulemaking notice accessible online in html format at http://www.pabulletin.com/secure/data/vol44/44-16/815.html.

Or in PDF format at http://www.pabulletin.com/secure/data/vol44/44-16/44_16_prm.pdf.

New York: http://www.dec.ny.gov/regulations/26402.html "Air Pollution Proposed, Emergency, and Recently Adopted Regulations"

Existing adopted regulations: http://www.dec.ny.gov/regs/2492.html "Chapter III- Air Resources" Part 227: Stationary Combustion Installations, Subpart 227-1 Stationary Combustion Installations, and Subpart 227-2 Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NOx) and Part 228: Surface Coating Processes, Commercial and Industrial Adhesives, Sealants and Primers. NB: Disclaimer by NYSDEC: "These regulations are presented as a quick reference tool. While they are believed to be accurate, they are not certified copies of the regulations and therefore should not be relied upon for legal interpretation. Also, linked on-line guidance documents and "overview" summaries of regulations are not the regulations themselves. The official written regulations published by the Department of State are the official source for NYSDEC regulations."

http://www.dec.ny.gov/regulations/36816.html "Regulatory Agenda DEC January 2014 Regulatory Agenda and 5-Year Rule Review:" Items listed include 6 NYCRR Part 222, Distributed Generation "a new regulation to establish emission standards for distributed generation," "6 NYCRR Subpart 227-1, Stationary Combustion Installations."

b. Non-OTR States:

Dallas Fort Worth:
Current Rules:
http://www.tceq.state.tx.us/rules/current.html
Texas NOx RACT Rules for the DFW 2008 Eight-Hour ozone nonattainment area (in development):

Enclosure 2: EPA Comments on Proposed Amendments to Chapters 121 and 129 Presumptive Reasonably Available Control Technology (RACT) requirements and RACT emission limitations for certain major stationary sources of oxides of nitrogen (NOx) and volatile organic compound (VOC) emissions. [44 Pa.B. 2392, April 19, 2014]

http://www5.tceq.state.tx.us/rules/index.cfm?fuseaction=external_reports.projectDetail&projectID=1524

Texas VOC RACT Rules for the DFW 2008 Eight-Hour ozone nonattainment area (in development):
http://www5.tceq.state.tx.us/rules/index.cfm?fuseaction=external_reports.projectDetail&projectID=1523

California Air Quality management District Rules can be accessed via:
http://www.arb.ca.gov/drdb/drdbltxt.htm.

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Attachment A to EPA's Comments on Proposed Amendments to Chapters 121 and 129 Presumptive RACT for NOx and VOC. [44 Pa.B. 2392, April 19, 2014]

State	Facility Name	Unit ID	Year	Avg NOx Rate (lb/MMBtu)	NOx Control(s)	Heat Input (MMBtu)	Operating Time	NOx (tons)	# of Months Reported	Gross Load (MW-h)	County	Facility ID (ORISPL)	Source Category	Unit Type	Fuel Type (Primary)	Fuel Type (Secondary)
PA	Bruce Mansfield	1	1995	0.390	LNB Technology w/ Overfire Air	18,855,058	3483.5	3,716.1	5	2,135,612	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	1996	0.400	LNB Technology w/ Overfire Air	21,838,265	3671.3	4,398.0	5	2,316,925	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	1997	0.343	LNB Technology w/ Overfire Air	20,871,254	3513.3	3,615.7	5	2,181,804	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	1998	0.419	LNB Technology w/ Overfire Air	22,754,012	3495.5	4,820.0	5	2,369,033	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	1999	0.313	LNB Technology w/ Overfire Air	15,838,831	2976.0	2,515.0	5	1,742,834	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2000	0.328	LNB Technology w/ Overfire Air	19,627,012	3510.0	3,255.8	5	2,430,768	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2001	0.388	LNB Technology w/ Overfire Air	19,148,442	3686.0	3,820.7	5	2,447,495	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2002	0.325	LNB Technology w/ Overfire Air	16,805,454	2822.3	2,856.9	5	2,012,931	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2003	0.078	LNB Technology w/ Overfire Air; SCR (Began May 01, 2003)	23,028,405	3489.0	884.4	5	2,812,911	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2004	0.076	LNB Technology w/ Overfire Air; SCR	24,524,828	3594.8	918.8	5	2,798,472	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2005	0.088	LNB Technology w/ Overfire Air; SCR	23,459,520	3415.3	1,008.1	5	2,805,817	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2006	0.112	LNB Technology w/ Overfire Air; SCR	26,671,303	3626.8	1,490.5	5	3,201,702	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2007	0.084	LNB Technology w/ Overfire Air; SCR	25,241,273	3449.8	1,007.9	5	2,923,872	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2008	0.082	LNB Technology w/ Overfire Air; SCR	19,833,989	2654.8	762.0	5	2,246,827	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2009	0.087	LNB Technology w/ Overfire Air; SCR	20,999,059	3188.9	866.6	5	2,378,943	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2010	0.099	LNB Technology w/ Overfire Air; SCR	24,576,019	3430.3	1,223.7	5	2,728,796	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2011	0.134	LNB Technology w/ Overfire Air; SCR	25,483,832	3474.8	1,725.1	5	2,850,947	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2012	0.122	LNB Technology w/ Overfire Air; SCR	21,176,236	2919.7	1,323.3	5	2,351,296	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	1	2013	0.167	LNB Technology w/ Overfire Air; SCR	26,632,251	3533.9	2,274.0	5	2,956,721	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	1995									6094				
PA	Bruce Mansfield	2	1996									6094				
PA	Bruce Mansfield	2	1997									6094				
PA	Bruce Mansfield	2	1998	0.373	LNB Technology (Dry Bottom only)	23,004,306	3552.0	4,353.9	5	2,516,058	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	1999	0.281	LNB Technology (Dry Bottom only)	18,740,867	3672.0	2,723.5	5	2,084,675	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2000	0.304	LNB Technology (Dry Bottom only)	18,282,390	3445.8	2,866.5	5	2,179,771	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2001	0.314	LNB Technology (Dry Bottom only)	14,815,152	2446.5	2,391.8	5	1,601,628	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2002	0.319	LNB Technology (Dry Bottom only)	25,259,003	3593.8	4,041.7	5	2,789,941	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2003	0.082	LNB Technology (Dry Bottom only); SCR (Began May 01, 2003)	24,770,790	3481.0	985.9	5	2,800,819	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2004	0.080	LNB Technology (Dry Bottom only); SCR	24,580,373	3585.8	961.0	5	2,780,946	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2005	0.085	LNB Technology (Dry Bottom only); SCR	25,863,693	3631.3	1,098.9	5	3,020,334	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2006	0.093	LNB Technology (Dry Bottom only); SCR	19,846,043	2774.0	891.7	5	2,242,058	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2007	0.080	LNB Technology (Dry Bottom only); SCR	26,994,695	3538.3	1,051.4	5	3,050,433	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2008	0.084	LNB Technology (Dry Bottom only); SCR	26,745,278	3552.0	1,078.6	5	3,024,454	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2009	0.097	LNB Technology (Dry Bottom only); SCR	22,469,661	3422.2	1,057.7	5	2,554,676	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2010	0.098	LNB Technology (Dry Bottom only); SCR	21,966,208	3138.6	996.7	5	2,530,688	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2011	0.107	LNB Technology (Dry Bottom only); SCR	25,339,530	3528.1	1,347.2	5	2,930,717	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2012	0.128	LNB Technology (Dry Bottom only); SCR	24,612,033	3567.4	1,612.6	5	2,824,261	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	2	2013	0.168	LNB Technology (Dry Bottom only); SCR	23,315,698	3243.5	1,958.3	5	2,697,260	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	1895									6094				
PA	Bruce Mansfield	3	1996									6094				
PA	Bruce Mansfield	3	1997	0.355	LNB Technology w/ Overfire Air	20,648,044	3566.5	3,719.6	5	2,242,197	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	1998	0.439	LNB Technology w/ Overfire Air	21,656,411	3440.8	4,845.4	5	2,327,009	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	1999	0.303	LNB Technology w/ Overfire Air	19,117,229	3672.0	2,985.6	5	2,050,427	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2000	0.363	LNB Technology w/ Overfire Air	23,538,515	3588.3	4,378.1	5	2,563,181	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2001	0.351	LNB Technology w/ Overfire Air	19,774,350	3465.3	3,624.0	5	2,269,762	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2002	0.415	LNB Technology w/ Overfire Air	23,160,115	3332.8	4,853.1	5	2,679,888	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2003	0.394	LNB Technology w/ Overfire Air	23,735,113	3322.3	4,736.7	5	2,684,155	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2004	0.080	LNB Technology w/ Overfire Air; SCR (Began Apr 24, 2004)	24,459,348	3581.5	964.1	5	2,949,353	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2005	0.074	LNB Technology w/ Overfire Air; SCR	25,929,504	3604.5	948.4	5	3,092,076	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2006	0.110	LNB Technology w/ Overfire Air; SCR	25,079,308	3579.3	1,355.5	5	3,077,340	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2007	0.119	LNB Technology w/ Overfire Air; SCR	22,067,274	2943.3	1,301.2	5	2,505,710	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2008	0.110	LNB Technology w/ Overfire Air; SCR	27,595,662	3490.8	1,491.3	5	3,057,799	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2009	0.086	LNB Technology w/ Overfire Air; SCR	24,351,610	3637.5	1,061.7	5	2,575,473	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	

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PA	Bruce Mansfield	3	2010	0.193	LNB Technology w/ Overfire Air; SCA	26,761,474	3515.0	2,614.8	5	2,932,474	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2011	0.079	LNB Technology w/ Overfire Air; SCR	26,371,458	3556.4	1,009.7	5	2,912,418	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2012	0.108	LNB Technology w/ Overfire Air; SCR	27,020,994	3668.1	1,478.7	5	2,915,658	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Bruce Mansfield	3	2013	0.171	LNB Technology w/ Overfire Air; SCR	26,414,387	3552.7	2,263.7	5	2,887,802	Beaver	6094	EGU	Dry bottom wall-fired boiler	Coal	
PA	Cheswick	1	1995	0.393	LNB Technology w/ Separated OFA	15,430,883	3351.8	3,075.6	5	1,579,312	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	1996	0.390	LNB Technology w/ Separated OFA	14,742,145	3438.0	2,942.0	5	1,487,075	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	1997	0.404	LNB Technology w/ Separated OFA	13,838,385	3129.8	2,853.4	5	1,338,227	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	1998	0.350	LNB Technology w/ Separated OFA	11,473,329	2699.3	2,201.7	5	1,063,888	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	1999	0.243	LNB Technology w/ Separated OFA	13,562,073	3318.3	1,736.5	5	1,288,444	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2000	0.323	LNB Technology w/ Separated OFA	14,966,773	2907.2	7,482.3	5	1,474,943	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2001	0.280	LNB Technology w/ Separated OFA	15,693,946	3441.5	2,271.8	5	1,507,975	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2002	0.279	LNB Technology w/ Separated OFA	15,050,656	3214.0	2,247.1	5	1,436,335	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2003	0.060	LNB Technology w/ Separated OFA, SCR (Began Apr 30, 2003)	14,952,137	3568.8	431.2	5	1,717,936	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2004	0.079	LNB Technology w/ Separated OFA; SCR	8,950,003	2112.8	320.2	5	917,589	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2005	0.105	LNB Technology w/ Separated OFA; SCR	12,365,928	3085.5	562.7	5	1,310,781	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2006	0.090	LNB Technology w/ Separated OFA; SCR	9,320,529	2196.3	370.3	5	999,349	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2007	0.190	LNB Technology w/ Separated OFA; SCR	10,934,264	2841.2	944.5	5	1,187,411	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2008	0.248	LNB Technology w/ Separated OFA; SCR	8,841,372	2690.5	962.6	5	915,803	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2009	0.171	LNB Technology w/ Separated OFA; SCR	9,765,422	2339.8	830.0	5	1,045,855	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2010	0.257	LNB Technology w/ Separated OFA; SCR	8,937,790	2122.1	1,182.5	5	911,134	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2011	0.239	LNB Technology w/ Separated OFA; SCR	14,352,570	3264.9	1,690.0	5	1,507,990	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2012	0.330	LNB Technology w/ Separated OFA; SCR	12,244,689	2843.2	2,142.1	5	1,290,586	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Cheswick	1	2013	0.328	LNB Technology w/ Separated OFA; SCR	11,326,390	2466.7	1,941.3	5	1,157,834	Allegheny	8226	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Homer City	1	1995									3122				
PA	Homer City	1	1996									3122				
PA	Homer City	1	1997	0.468	LNB Technology w/ Overfire Air	20,807,153	3425.0	4,907.8	5	2,083,857	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	1998	0.417	LNB Technology w/ Overfire Air	16,685,039	2999.5	3,485.5	5	1,735,294	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	1999	0.381	LNB Technology w/ Overfire Air	18,427,721	3453.5	3,630.6	5	1,843,512	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2000	0.400	LNB Technology w/ Overfire Air	18,042,583	3502.5	3,768.1	5	1,850,494	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2001	0.273	LNB Technology w/ Overfire Air; SCR (Began Jun 30, 2001)	16,636,659	3409.7	2,295.5	5	1,916,408	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2002	0.439	LNB Technology w/ Overfire Air; SCR	11,012,975	2155.5	2,450.3	5	1,275,975	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2003	0.111	LNB Technology w/ Overfire Air; SCR	20,667,003	3544.3	1,100.9	5	2,281,089	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2004	0.204	LNB Technology w/ Overfire Air; SCR	18,587,944	3400.4	1,809.1	5	2,083,100	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2005	0.070	LNB Technology w/ Overfire Air; SCR	20,688,017	3531.7	696.1	5	2,279,229	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2006	0.067	LNB Technology w/ Overfire Air; SCR	19,792,060	3549.9	651.0	5	2,218,858	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2007	0.113	LNB Technology w/ Overfire Air; SCR	20,170,576	3564.6	1,109.7	5	2,153,022	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2008	0.191	LNB Technology w/ Overfire Air; SCR	12,575,108	2469.8	1,192.1	5	1,384,658	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2009	0.114	LNB Technology w/ Overfire Air; SCR	13,633,624	3255.8	764.0	5	1,516,162	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2010	0.143	LNB Technology w/ Overfire Air; SCR	13,545,412	2924.4	971.3	5	1,486,322	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2011	0.188	LNB Technology w/ Overfire Air; SCR	15,078,293	3305.9	1,471.4	5	1,649,627	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2012	0.176	LNB Technology w/ Overfire Air; SCR	14,571,514	3407.2	1,301.5	5	1,552,061	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	1	2013	0.304	LNB Technology w/ Overfire Air; SCR	16,304,439	3590.2	2,522.5	5	1,774,144	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	1995									3122				
PA	Homer City	2	1996									3122				
PA	Homer City	2	1997	0.432	LNB Technology w/ Overfire Air	19,728,941	3489.3	4,269.7	5	2,065,596	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	2	1998	0.416	LNB Technology w/ Overfire Air	20,185,391	3535.0	4,238.7	5	2,137,060	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	2	1999	0.375	LNB Technology w/ Overfire Air	18,561,688	3634.0	3,584.1	5	1,982,727	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	2	2000	0.416	LNB Technology w/ Overfire Air, SCR (Began Jun 30, 2000)	13,108,235	2705.8	2,833.0	5	1,457,880	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	2	2001	0.371	LNB Technology w/ Overfire Air, SCR	17,648,412	3460.0	3,330.1	5	1,998,660	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	2	2002	0.392	LNB Technology w/ Overfire Air; SCR	11,993,093	2310.4	2,349.8	5	1,365,096	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2003	0.145	LNB Technology w/ Overfire Air, SCR	19,196,405	3374.6	1,358.7	5	2,159,192	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2004	0.205	LNB Technology w/ Overfire Air; SCR	17,635,413	3234.6	1,731.7	5	1,964,262	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2005	0.091	LNB Technology w/ Overfire Air; SCR	20,452,267	3596.0	913.0	5	2,336,526	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2006	0.083	LNB Technology w/ Overfire Air; SCR	17,021,477	3234.4	642.3	5	1,888,732	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2007	0.090	LNB Technology w/ Overfire Air; SCR	18,820,460	3490.1	806.7	5	2,088,524	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2008	0.185	LNB Technology w/ Overfire Air; SCR	18,964,341	3507.9	1,729.8	5	2,027,608	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	

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PA	Homer City	2	2009	0.118	LNB Technology w/ Overfire Air; SCR	17,459,876	3581.1	1,013.8	5	1,892,456	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2010	0.161	LNB Technology w/ Overfire Air; SCR	14,733,525	2836.3	1,173.8	5	1,580,572	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2011	0.224	LNB Technology w/ Overfire Air; SCR	12,466,420	2731.9	1,419.1	5	1,340,116	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2012	0.227	LNB Technology w/ Overfire Air; SCR	14,856,859	3239.3	1,764.7	5	1,487,105	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	2	2013	0.328	LNB Technology w/ Overfire Air; SCR	15,187,980	3194.9	2,552.5	5	1,556,044	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	1995									3122				
PA	Homer City	3	1996									3122				
PA	Homer City	3	1997	0.399	LNB Technology w/ Overfire Air	18,020,298	3454.8	3,615.8	5	1,928,411	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	3	1998	0.418	LNB Technology w/ Overfire Air	19,559,848	3500.3	4,125.6	5	2,053,753	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	3	1999	0.320	LNB Technology w/ Overfire Air	14,867,808	2826.8	2,453.8	5	1,534,344	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	3	2000	0.397	LNB Technology w/ Overfire Air	20,842,362	3672.0	4,118.2	5	2,161,763	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	3	2001	0.440	LNB Technology w/ Overfire Air, SCR (Began Jun 30, 2001)	15,594,928	3062.4	3,504.3	5	1,670,900	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas
PA	Homer City	3	2002	0.416	LNB Technology w/ Overfire Air; SCR	19,208,304	3477.9	4,064.4	5	2,218,640	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2003	0.140	LNB Technology w/ Overfire Air; SCR	18,362,711	3271.5	1,174.6	5	2,081,965	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2004	0.114	LNB Technology w/ Overfire Air; SCR	21,054,135	3603.3	1,137.8	5	2,336,160	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2005	0.087	LNB Technology w/ Overfire Air; SCR	17,136,300	2812.3	713.7	5	1,843,551	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2006	0.108	LNB Technology w/ Overfire Air; SCR	18,486,841	3324.3	958.6	5	2,127,191	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2007	0.187	LNB Technology w/ Overfire Air; SCR	20,521,399	3514.3	1,910.9	5	2,213,823	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2008	0.237	LNB Technology w/ Overfire Air; SCR	16,529,704	3334.2	1,991.4	5	1,761,160	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2009	0.169	LNB Technology w/ Overfire Air; SCR	16,813,747	3367.0	1,433.8	5	1,875,294	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2010	0.139	LNB Technology w/ Overfire Air; SCR	17,147,386	3333.6	1,203.0	5	1,808,060	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2011	0.199	LNB Technology w/ Overfire Air; SCR	16,337,111	3544.4	1,629.7	5	1,845,939	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2012	0.215	LNB Technology w/ Overfire Air; SCR	12,983,037	3145.5	1,421.1	5	1,415,239	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Homer City	3	2013	0.332	LNB Technology w/ Overfire Air; SCR	18,856,788	3451.5	3,235.2	5	1,835,960	Indiana	3122	EGU	Dry bottom wall-fired boiler	Coal	
PA	Keystone	1	1995									3136				
PA	Keystone	1	1996									3136				
PA	Keystone	1	1997	0.371	LNB Technology w/ Closed-coupled/Separated OFA	28,228,799	3672.0	5,225.5	5	3,123,307	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	1998	0.324	LNB Technology w/ Closed-coupled/Separated OFA	28,886,127	3652.8	4,675.7	5	3,197,587	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	1999	0.303	LNB Technology w/ Closed-coupled/Separated OFA	21,584,554	2832.0	3,278.7	5	2,417,814	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2000	0.277	LNB Technology w/ Closed-coupled/Separated OFA	20,359,126	2865.0	2,843.2	5	2,291,141	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2001	0.300	LNB Technology w/ Closed-coupled/Separated OFA	26,597,623	3579.5	4,002.4	5	2,963,022	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2002	0.299	LNB Technology w/ Closed-coupled/Separated OFA	26,936,991	3503.9	4,042.0	5	2,962,918	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2003	0.042	LNB Technology w/ Closed-coupled/Separated OFA; SCR (Began Apr 18, 2003)	27,982,584	3594.3	582.2	5	3,095,706	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2004	0.085	LNB Technology w/ Closed-coupled/Separated OFA; SCR	25,822,343	3375.1	1,066.3	5	2,889,537	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2005	0.044	LNB Technology w/ Closed-coupled/Separated OFA; SCR	28,087,735	3580.9	601.3	5	3,073,601	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2006	0.043	LNB Technology w/ Closed-coupled/Separated OFA; SCR	28,256,121	3575.1	599.4	5	3,087,430	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2007	0.065	LNB Technology w/ Closed-coupled/Separated OFA; SCR	26,972,207	3579.7	872.4	5	3,119,412	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2008	0.116	LNB Technology w/ Closed-coupled/Separated OFA; SCR	27,558,227	3598.8	1,574.1	5	3,123,370	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2009	0.067	LNB Technology w/ Closed-coupled/Separated OFA; SCR	21,743,866	3036.3	681.3	5	2,480,198	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2010	0.052	LNB Technology w/ Closed-coupled/Separated OFA; SCR	29,271,097	3672.0	759.9	5	3,255,811	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2011	0.372	LNB Technology w/ Closed-coupled/Separated OFA; SCR	25,982,263	3604.3	4,854.6	5	2,761,902	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2012	0.365	LNB Technology w/ Closed-coupled/Separated OFA; SCR	25,039,822	3543.2	4,660.6	5	2,685,580	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	1	2013	0.175	LNB Technology w/ Closed-coupled/Separated OFA; SCR	23,329,051	3244.7	1,823.7	5	2,504,629	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	1995									3136				
PA	Keystone	2	1996									3136				
PA	Keystone	2	1997	0.391	LNB Technology w/ Closed-coupled/Separated OFA	28,642,741	3523.5	5,568.0	5	3,011,333	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	1998	0.361	LNB Technology w/ Closed-coupled/Separated OFA	28,851,742	3556.5	5,195.4	5	3,091,478	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	1999	0.301	LNB Technology w/ Closed-coupled/Separated OFA	27,353,288	3617.8	4,123.5	5	3,142,639	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2000	0.300	LNB Technology w/ Closed-coupled/Separated OFA	25,356,544	3598.0	3,804.3	5	2,963,159	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2001	0.304	LNB Technology w/ Closed-coupled/Separated OFA	25,967,026	3614.0	3,959.3	5	2,990,788	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2002	0.301	LNB Technology w/ Closed-coupled/Separated OFA	23,543,396	3335.1	3,588.2	5	2,733,895	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2003	0.048	LNB Technology w/ Closed-coupled/Separated OFA; SCR (Began Feb 09, 2003)	25,490,114	3300.8	575.5	5	2,833,053	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2004	0.060	LNB Technology w/ Closed-coupled/Separated OFA; SCR	23,111,948	3063.6	678.4	5	2,639,591	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2005	0.060	LNB Technology w/ Closed-coupled/Separated OFA; SCR	25,642,709	3481.0	717.6	5	2,933,857	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2006	0.082	LNB Technology w/ Closed-coupled/Separated OFA; SCR	27,688,081	3663.5	1,114.3	5	3,154,669	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas

PA	Keystone	2	2007	0.045	LNB Technology w/ Closed-coupled/Separated OFA; SCR	26,209,253	3446.2	568.4	5	2,951,609	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2008	0.043	LNB Technology w/ Closed-coupled/Separated OFA; SCR	28,579,775	3660.0	604.8	5	3,170,558	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2009	0.077	LNB Technology w/ Closed-coupled/Separated OFA; SCR	25,560,221	3423.2	951.8	5	2,828,983	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2010	0.045	LNB Technology w/ Closed-coupled/Separated OFA; SCR	27,870,187	3508.9	620.4	5	3,100,282	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2011	0.363	LNB Technology w/ Closed-coupled/Separated OFA; SCR	27,712,934	3604.9	5,044.3	5	2,924,352	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2012	0.343	LNB Technology w/ Closed-coupled/Separated OFA; SCR	22,033,114	3037.6	3,774.4	5	2,352,216	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Keystone	2	2013	0.179	LNB Technology w/ Closed-coupled/Separated OFA; SCR	24,655,104	3401.9	2,046.4	5	2,758,549	Armstrong	3136	EGU	Tangentially-fired	Coal	Pipeline Natural Gas
PA	Montour	1	1995									3149				
PA	Montour	1	1996									3149				
PA	Montour	1	1997									3149				
PA	Montour	1	1998	0.430	LNB Technology w/ Closed-coupled/Separated OFA	21,841,703	3386.5	4,797.2	5	2,196,432	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	1999	0.314	LNB Technology w/ Closed-coupled/Separated OFA	13,371,009	2392.8	2,141.2	5	1,469,407	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2000	0.394	LNB Technology w/ Closed-coupled/Separated OFA	20,019,913	3600.9	3,980.2	5	2,331,183	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2001	0.145	LNB Technology w/ Closed-coupled/Separated OFA; SCR (Began Jun 01, 2001)	16,333,660	3048.3	1,056.2	5	1,883,830	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2002	0.093	LNB Technology w/ Closed-coupled/Separated OFA; SCR	19,499,244	3470.9	852.3	5	2,276,756	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2003	0.044	LNB Technology w/ Closed-coupled/Separated OFA; SCR	21,603,519	3672.0	464.8	5	2,481,738	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2004	0.061	LNB Technology w/ Closed-coupled/Separated OFA; SCR	19,915,869	3454.7	587.7	5	2,281,125	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2005	0.084	LNB Technology w/ Closed-coupled/Separated OFA; SCR	20,547,883	3527.5	720.0	5	2,397,830	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2006	0.058	LNB Technology w/ Closed-coupled/Separated OFA; SCR	19,891,173	3426.4	554.9	5	2,393,420	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2007	0.065	LNB Technology w/ Closed-coupled/Separated OFA; SCR	20,670,042	3494.7	638.7	5	2,403,224	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2008	0.105	LNB Technology w/ Closed-coupled/Separated OFA; SCR	12,050,145	2174.1	569.7	5	1,316,747	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2009	0.093	LNB Technology w/ Closed-coupled/Separated OFA; SCR	20,332,034	3311.0	886.3	5	2,212,179	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2010	0.141	LNB Technology w/ Closed-coupled/Separated OFA; SCR	20,833,273	3574.4	1,438.8	5	2,452,989	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2011	0.332	LNB Technology w/ Closed-coupled/Separated OFA; SCR	19,907,183	3456.5	3,298.4	5	2,288,730	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2012	0.402	LNB Technology w/ Closed-coupled/Separated OFA; SCR	17,697,787	3492.7	3,542.5	5	2,025,658	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	1	2013	0.398	LNB Technology w/ Closed-coupled/Separated OFA; SCR	14,260,139	3032.0	2,863.7	5	1,527,191	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	1995									3149				
PA	Montour	2	1996									3149				
PA	Montour	2	1997									3149				
PA	Montour	2	1998	0.381	LNB Technology w/ Closed-coupled/Separated OFA	22,841,743	3430.5	4,444.8	5	2,278,250	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	1999	0.305	LNB Technology w/ Closed-coupled/Separated OFA	19,746,455	3576.5	3,060.6	5	2,223,135	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2000	0.158	LNB Technology w/ Closed-coupled/Separated OFA; SCR (Began Jun 01, 2000)	17,630,961	2924.1	1,393.3	5	2,026,325	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2001	0.080	LNB Technology w/ Closed-coupled/Separated OFA; SCR	21,753,226	3610.9	861.6	5	2,438,404	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2002	0.101	LNB Technology w/ Closed-coupled/Separated OFA; SCR	20,492,177	3573.5	969.3	5	2,348,387	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2003	0.047	LNB Technology w/ Closed-coupled/Separated OFA; SCR	19,183,101	3479.8	430.0	5	2,329,686	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2004	0.049	LNB Technology w/ Closed-coupled/Separated OFA; SCR	21,525,141	3605.4	509.2	5	2,490,505	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2005	0.067	LNB Technology w/ Closed-coupled/Separated OFA; SCR	20,372,742	3447.9	637.6	5	2,347,440	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2006	0.058	LNB Technology w/ Closed-coupled/Separated OFA; SCR	20,449,998	3481.0	565.2	5	2,429,026	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2007	0.106	LNB Technology w/ Closed-coupled/Separated OFA; SCR	16,057,060	2598.9	820.6	5	1,892,161	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2008	0.094	LNB Technology w/ Closed-coupled/Separated OFA; SCR	21,078,898	3362.9	978.0	5	2,275,535	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2009	0.113	LNB Technology w/ Closed-coupled/Separated OFA; SCR	19,200,754	3186.7	1,073.3	5	2,166,882	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2010	0.212	LNB Technology w/ Closed-coupled/Separated OFA; SCR	13,039,974	2297.1	1,402.4	5	1,434,823	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2011	0.316	LNB Technology w/ Closed-coupled/Separated OFA; SCR	19,819,379	3582.5	3,132.2	5	2,359,283	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2012	0.414	LNB Technology w/ Closed-coupled/Separated OFA; SCR	18,555,077	3418.3	3,793.7	5	1,986,066	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil
PA	Montour	2	2013	0.424	LNB Technology w/ Closed-coupled/Separated OFA; SCR	14,411,895	3094.1	3,050.3	5	1,575,974	Montour	3149	EGU	Tangentially-fired	Coal	Other Oil

Attachment B to EPA's Comments on Proposed Amendments to Chapters 121 and 129 Presumptive RACT for NOx and VOC. [44 Pa.B. 2392, April 19, 2014]

Attachment B - Summary Data for 2011, Latest Year of Data and Lowest Average Emission Rate Year								
			Most recent Year		Base Year NOx Rate		Minimum NOx Rate	
Plant	Unit	SCR/SNCR	Year	NOx Rate	Year	NOx Rate	Year	NOx Rate
Electric Utility - Dry bottom wall-fired boiler								
Bruce Mansfield	1	SCR	2013	0.167	2011	0.134	2004	0.076
Bruce Mansfield	2	SCR	2013	0.168	2011	0.107	2004	0.080
Bruce Mansfield	3	SCR	2013	0.171	2011	0.079	2005	0.074
Homer City	1	SCR	2013	0.304	2011	0.188	2006	0.067
Homer City	2	SCR	2013	0.328	2011	0.224	2006	0.083
Homer City	3	SCR	2013	0.332	2011	0.199	2005	0.087
Electric Utility - Tangentially-fired								
Cheswick	1	SCR	2013	0.328	2011	0.239	2004	0.079
Keystone	1	SCR	2013	0.175	2011	0.372	2005	0.043
Keystone	2	SCR	2013	0.179	2011	0.363	2008	0.043
Montour	1	SCR	2013	0.398	2011	0.332	2003	0.044
Montour	2	SCR	2013	0.424	2011	0.316	2003	0.047
Cogeneration - Dry bottom wall-fired boiler								
AES Beaver Valley LLC	32	SNCR	2013	0.557	2011	0.415	2006	0.402
AES Beaver Valley LLC	33	SNCR	2013	0.584	2011	0.451	2009	0.281
AES Beaver Valley LLC	34	SNCR	2013	0.607	2011	0.445	2004	0.363
AES Beaver Valley LLC	35	SNCR	2013	0.443	2011	0.468	2005	0.318
Small Power Producer - Circulating fluidized bed boiler								
Panther Creek Energy Facility	1	Ammonia I	2013	0.119	2011	0.130	2005	0.105
Panther Creek Energy Facility	2	Ammonia I	2013	0.117	2011	0.121	2005	0.109
Small Power Producer - Circulating fluidized bed boiler								
Scrubgrass Generating Plant	1	SNCR	2013	0.142	2011	0.119	2005	0.057
Scrubgrass Generating Plant	2	SNCR	2013	0.151	2011	0.128	2004	0.068
Piney Creek Power Plant	31	SNCR	2012	0.142	2011	0.129	2004	0.075

Attachment B to EPA's Comments on Proposed Amendments to Chapters 121 and 129 Presumptive RACT for NOx and VOC. [44 Pa.B. 2392, April 19, 2014]

Pulp & Paper Mill - Circulating fluidized bed boiler								
P H Glatfelter Company	36	SNCR	2013	0.179	2011	0.137	2012	0.105
Electric Utility - Dry bottom wall-fired boiler								
Shawville	1	SNCR	2013	0.406	2011	0.371	2011	0.371
Shawville	2	SNCR	2013	0.393	2011	0.399	2005	0.396
New Castle	3	SNCR	2013	0.330	2011	0.341	2006	0.281
New Castle	4	SNCR	2013	0.323	2011	0.327	2006	0.280
New Castle	5	SNCR	2013	0.377	2011	0.406	2006	0.337
Electric Utility - Tangentially-fired								
Shawville	3	SNCR	2013	0.365	2011	0.383	2005	0.348
Shawville	4	SNCR	2013	0.396	2011	0.363	2005	0.348
Electric Utility - Cell burner boiler								
Hatfield's Ferry Power Station	3	SNCR	2013	0.444	2011	0.432	2005	0.270
Electric Utility - Dry bottom vertically-fired boiler								
Elrama	1	SNCR	2011	0.498	2011	0.498	2003	0.381
Elrama	2	SNCR	2012	0.432	2011	0.455	2003	0.376
Elrama	3	SNCR	2012	0.416	2011	0.521	2003	0.384
Elrama	4	SNCR	2012	0.352	2011	0.455	2004	0.375

Attachment C to EPA's Comments on Proposed Amendments to Chapters 121 and 129 Presumptive RACT for NOx and VOC. [44 Pa.B. 2392, April 19, 2014]

State	Cite	Category	Fuel/type	Applicability Thresholds	Compliance date	Emission limit	Units	Averaging Period	Notes
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Coal - Wet Bottom- Tangential Fired		Prior to December 14, 2012	1.00	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Coal - Dry Bottom- Tangential Fired		Prior to December 14, 2012	0.38	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Coal - Wet Bottom-Face Fired		Prior to December 14, 2012	1.00	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Coal - Dry Bottom-Face Fired		Prior to December 14, 2012	0.45	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Coal - Wet Bottom-Cyc		Prior to December 14, 2012	0.60	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Coal - Dry Bottom-Cyc		Prior to December 14, 2012	0.55	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	O/G- Tangential Fired		Prior to December 14, 2012	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	O/G-Face Fired		Prior to December 14, 2012	0.28	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	O/G-Cyclone		Prior to December 14, 2012	0.43	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Gas-- Face/Tangential Fired		Prior to December 14, 2012	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Gas-Cyclone		Prior to December 14, 2012	0.43	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Coal -- Face/Tangential Fired-Cyc		After December 14, 2012 through May 1, 2015	1.50	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	O/G - Tangential Fired		After December 14, 2012 through May 1, 2015	2.00	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	O/G-Face Fired		After December 14, 2012 through May 1, 2015	2.80	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	

NJ	N.J.A.C. 7:27-19.4	EGU Boiler	O/G-Cyclone		After December 14, 2012 through May 1, 2015	4.30	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	G – Face/Tangential Fired		After December 14, 2012 through May 1, 2015	2.00	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	G -Cyclone		After December 14, 2012 through May 1, 2015	4.30	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	C - any		After May 1, 2015	1.50	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Oil Heavier than No 2		After May 1, 2015	2.00	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Oil No 2 or lighter		After May 1, 2015	1.00	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.4	EGU Boiler	Gas		After May 1, 2015	1.00	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only- Tangential	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only- Face	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only- Cyclone	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	No. 2 Fuel oil only- Tangential	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.12	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	No. 2 Fuel oil only- Face	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.12	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	No. 2 Fuel oil only- Cyclone	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.12	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Refinery fuel gas and other gaseous fuels- Tangential	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."

NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Refinery fuel gas and other gaseous fuels- Face	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Refinery fuel gas and other gaseous fuels- Cyclone	>= 50 & < 100 mmBTU/hr	March 7, 2007*	N/A	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Other liquid fuels- Tangential	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.30	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Other liquid fuels- Face	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.30	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Other liquid fuels- Cyclone	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.30	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Wet Bottom- Tangential	>= 50 & < 100 mmBTU/hr	March 7, 2007*	1.00	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Wet Bottom- Face	>= 50 & < 100 mmBTU/hr	March 7, 2007*	1.00	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Wet Bottom- Cyclone	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.55	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Dry Bottom- Tangential	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.38	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Dry Bottom- Face	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.43	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."

NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal -- Dry Bottom- Cyclone	>= 50 & < 100 mmBTU/hr	March 7, 2007*	0.55	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only- Tangential	>= 100 mmBTU/hr	March 7, 2007*	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only- Face	>= 100 mmBTU/hr	March 7, 2007*	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only- Cyclone	>= 100 mmBTU/hr	March 7, 2007*	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Refinery fuel gas and other gaseous fuels- Tangential	>= 100 mmBTU/hr	March 7, 2007*	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Refinery fuel gas and other gaseous fuels- Face	>= 100 mmBTU/hr	March 7, 2007*	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Refinery fuel gas and other gaseous fuels- Cyclone	>= 100 mmBTU/hr	March 7, 2007*	N/A	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Fuel oil and/or natural gas-Tangential	>= 100 mmBTU/hr	March 7, 2007*	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Fuel oil and/or natural gas-Face	>= 100 mmBTU/hr	March 7, 2007*	0.28	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Fuel oil and/or natural gas-Cyclone	>= 100 mmBTU/hr	March 7, 2007*	0.43	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."

NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Wet Bottom- Tangential	>= 100 mmBTU/hr	March 7, 2007*	1.00	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Wet Bottom- Face	>= 100 mmBTU/hr	March 7, 2007*	1.00	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Wet Bottom- Cyclone	>= 100 mmBTU/hr	March 7, 2007*	0.60	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Dry Bottom- Tangential	>= 100 mmBTU/hr	March 7, 2007*	0.38	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Dry Bottom- Face	>= 100 mmBTU/hr	March 7, 2007*	0.45	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Coal – Dry Bottom- Cyclone	>= 100 mmBTU/hr	March 7, 2007*	0.55	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	Applied to units at a "major NOx facility."
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery			* Through April 30, 2010 if no modification needed, otherwise April 30, 2011				
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only	>= 25 & < 100 mmBTU/hr	May 1, 2011/May 1, 2012	0.05	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	No 2 Fuel Oil	>= 25 & < 100 mmBTU/hr	May 1, 2011/May 1, 2012	0.08	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Other gaseous fuels (excluding refinery gas)	>= 25 & < 100 mmBTU/hr	May 1, 2011/May 1, 2012	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required

NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	other liquid fuels	>= 25 & < 100 mmBTU/hr	May 1, 2011/May 1, 2012	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Duel fuel - natural gas/fuel oil	>= 25 & < 100 mmBTU/hr	May 1, 2011/May 1, 2012	0.12	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Natural gas only	>= 100 mmBTU/hr	May 1, 2010/May 1, 2011	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	No 2 Fuel Oil	>= 100 mmBTU/hr	May 1, 2010/May 1, 2011	0.10	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Other gaseous fuels (excluding refinery gas)	>= 100 mmBTU/hr	May 1, 2010/May 1, 2011	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	other liquid fuels	>= 100 mmBTU/hr	May 1, 2010/May 1, 2011	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.7	I/C/I boiler or other indirect heat exchanger not at petroleum refinery	Duel fuel - natural gas/fuel oil	>= 100 mmBTU/hr	May 1, 2010/May 1, 2011	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Oil fuel	>= 30 mmBTU/hr	until March 7, 2007	0.40	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Gas fuel	>= 30 mmBTU/hr	until March 7, 2007	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Oil fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	0.40	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Must be at a "NOx Budget Source"
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Gas fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Must be at a "NOx Budget Source"
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Oil fuel	HEDD unit	May 20, 2009 through April 30, 2015	0.40	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	HEDD Unit

NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Gas fuel	HEDD unit	May 20, 2009 through April 30, 2015	0.20	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	HEDD Unit
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - oil fuel	>= 30 mmBTU/hr	until March 7, 2007	0.35	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - gas fuel	>= 30 mmBTU/hr	until March 7, 2007	0.15	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - oil fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	0.35	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Must be at a "NOx Budget Source"
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - gas fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	0.15	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	Must be at a "NOx Budget Source"
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - oil fuel	HEDD Unit	May 20, 2009 through April 30, 2015	0.35	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	HEDD Unit
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - gas fuel	HEDD Unit	May 20, 2009 through April 30, 2015	0.15	lb Nox/mmBTU input	See note below re: N.J.A.C. 7:27-1	HEDD Unit
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Oil fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	3.0	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not at NOx Budget Source
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Gas fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	2.2	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not at NOx Budget Source
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - oil fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	2.0	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not at NOx Budget Source
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - gas fuel	>= 25 mmBTU/hr	March 7, 2007 through May 19, 2009	1.3	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not at NOx Budget Source
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Oil fuel	Not HEDD	After May 20, 2009	3.0	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not a HEDD Unit
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Gas fuel	Not HEDD	After May 20, 2009	2.2	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not a HEDD Unit
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - oil fuel	Not HEDD	After May 20, 2009	2.0	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not a HEDD Unit
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - gas fuel	Not HEDD	After May 20, 2009	1.3	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Not a HEDD Unit

NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Oil fuel	>= 15 MW or HEDD unit	May 1, 2015	1.60	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Applies to units that commenced operation on or after May 1, 2005
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Simple Cycle Gas fuel	>= 15 MW or HEDD unit	May 1, 2015	1.00	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Applies to units that commenced operation on or after May 1, 2005
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - oil fuel	>= 15 MW or HEDD unit	May 1, 2015	1.50	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Applies to units that commenced operation on or after May 1, 2005
NJ	N.J.A.C. 7:27-19.5	Stationary combustion turbines	Combined Cycle/Regenerative Cycle - gas fuel	>= 15 MW or HEDD unit	May 1, 2015	0.75	lb NOx/Mw-hr output	See note below re: N.J.A.C. 7:27-1	Applies to units that commenced operation on or after May 1, 2005
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	rich-burn - gaseous fuel	>= 500 bhp	Before March 7, 2007	1.5	g/bhp - hr	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn -- gaseous fuel	>= 500 bhp	Before March 7, 2007	2.5	g/bhp - hr	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn --liquid fuel	>= 500 bhp	Before March 7, 2007	8.0	g/bhp - hr	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	rich-burn - gaseous or liquid fuel	>= 148 kW output	After March 7, 2007	1.5	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; applies to two or more units >= 37 kW output each but having combined output >= 148 kW
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn -- gaseous fuel	>= 148 kW output	After March 7, 2007	1.5	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; 1.5 g/bhp-hr or 80% reduction; applies to two or more units >= 37 kW output each but having combined output >= 148 kW
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn -- liquid fuel	>= 148 kW output	After March 7, 2007	2.3	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; applies to two or more units >= 37 kW output each but having combined output >= 148 kW
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn -- duel (gaseous/liquid) fuel	>= 148 kW output	After March 7, 2007	2.3	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; applies to two or more units >= 37 kW output each but having combined output >= 148 kW

NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	rich-burn - gaseous or liquid fuel	>= 500 bhp & >+ 370 KW	After March 7, 2007	1.5	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; applies to two or more units >= 37 kW output each but having combined output >= 148 kW
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn -- gaseous fuel	>= 500 bhp & >+ 370 KW	After March 7, 2007	1.5	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; 1.5 g/bhp-hr or 80% reduction; applies to two or more units >= 37 kW output each but having combined output >= 148 kW
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn -- liquid fuel	>= 500 bhp & >+ 370 KW	After March 7, 2007	2.3	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; applies to two or more units >= 37 kW output each but having combined output >= 148 kW
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	lean burn -- duel (gaseous/liquid) fuel	>= 500 bhp & >+ 370 KW	After March 7, 2007	2.3	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity; applies to two or more units >= 37 kW output each but having combined output >= 148 kW
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	any	>= 37 kW output	After March 7, 2007	0.90	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity & commenced operation after March 7, 2007.
NJ	N.J.A.C. 7:27-19.8	Stationary reciprocating engines	any	>= 37 kW output	After March 7, 2007	0.90	g/bhp - hr	See note below re: N.J.A.C. 7:27-1	Must be used for generating electricity & modified after March 7, 2007.
NJ	N.J.A.C. 7:27-19.9	Asphalt pavement production dryer	Natural gas	<100 mmBTU/hr	May 1, 2011/May 1, 2012	75	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.9	Asphalt pavement production dryer	No 2 Fuel Oil	<100 mmBTU/hr	May 1, 2011/May 1, 2012	100	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.9	Asphalt pavement production dryer	No 4 or heavier oil. On-spec used oil or combination	<100 mmBTU/hr	May 1, 2011/May 1, 2012	150	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.9	Asphalt pavement production dryer	Natural gas	>=100 mmBTU/hr	May 1, 2010/May 1, 2011	75	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.9	Asphalt pavement production dryer	No 2 Fuel Oil	>=100 mmBTU/hr	May 1, 2010/May 1, 2011	100	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required

NJ	N.J.A.C. 7:27-19.9	Asphalt pavement production dryer	No 4 or heavier oil. On-spec used oil or combination	>=100 mmBTU/hr	May 1, 2010/May 1, 2011	150	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	Earlier date if no modification is required/later date if modification is required
NJ	N.J.A.C. 7:27-19.10	Glass manufacturing furnaces						See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.10	Glass manufacturing furnaces	specialty container glass	>= 7 tons glass/day & PTE >10 TPY NOx	First start-up date post-rebricking after May 1, 2010	4.0	lbs NOx/ton glass removed	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.10	Glass manufacturing furnaces	borosilicate recipe glass	>= 5 tons glass/day & PTE >10 TPY NOx	First start-up date post-rebricking after May 1, 2010	4.0	lbs NOx/ton glass removed	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.10	Glass manufacturing furnaces	pressed glass, blown glass or fiberglass	Furnace PTE >10 TPY NOx	First start-up date post-rebricking after May 1, 2010	4.0	lbs NOx/ton glass removed	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.10	Glass manufacturing furnaces	commercial container	>= 14 tons glass/day & PTE >10 TPY NOx	First start-up date post-rebricking after May 1, 2010	4.0	lbs NOx/ton glass removed	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.10	Glass manufacturing furnaces	flat glass	Furnace PTE >10 TPY NOx	First start-up date post-rebricking after May 1, 2010	9.2	lbs NOx/ton glass removed	See note below re: N.J.A.C. 7:27-19.15	
NJ	N.J.A.C. 7:27-19.12	Municipal solid waste (MSW) incinerators		any size	July 18, 2009	150	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	If compliance is by optimizing the existing NOx air pollution control system without modifying the MSW incinerator
NJ	N.J.A.C. 7:27-19.12	Municipal solid waste (MSW) incinerators		any size	May 1, 2011	150	ppmvd NOx @7% O2	See note below re: N.J.A.C. 7:27-1	If compliance is by installing a new NOx air pollution control system on an existing MSW incinerator or by physically modifying an existing MSW incinerator
NJ	N.J. A.C. 7:27-19.15	Averaging periods	Source with or required to have CEMS					24 hr calendar day May 1 to Sept 30; otherwise 30 day.	
NJ	N.J. A.C. 7:27-19.15	Averaging periods	Source without nor required to have CEMS					average of 3 1-hour tests each of 60 consecutive minutes	
DE	Reg. 1146	EGU	Coal or Residual Oil	>25 MW	On and after January 1, 2009 through 12/31/2011	0.15	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1146	EGU	Coal or Residual Oil	>25 MW	On and after January 1, 2012	0.125	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1142	Boiler	any boiler May 1st - Sept 30th	>100 mmBTU/hr not EGU or covered by Reg. 1112	After May 1, 2004	0.10	lb Nox/mmBTU input	24 hr cal day	

DE	Reg. 1142	Boiler	other times of year	>100 mmBTU/hr not EGU or covered by Reg. 1112	After May 1, 2004	0.25	lb Nox/mmBTU input	24 hr cal day	
DE	Reg. 1142	Petroleum Refineries - Boiler # 1		>= 200 mmBTU/Hour	On and after December 31, 2008	0.015	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1142	Petroleum Refineries - Boiler # 3		>= 200 mmBTU/Hour	On and after May 1, 2011	0.015	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1142	Petroleum Refineries - Boiler # 4		>= 200 mmBTU/Hour	On and after May 1, 2011	0.015	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1142	Petroleum Refineries - Fluid Catalytic Cracking Unit CO boiler		>= 200 mmBTU/Hour	On and after December 31, 2008	20.00	ppmvd @ 0% O2	7-day rolling	
DE	Reg. 1142	Petroleum Refineries - Crude Unit Vacuum Heater		>= 200 mmBTU/Hour	On and after December 31, 2008	0.04	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1142	Petroleum Refineries - Continuous Catalyst Regenerator Reformer Heater		>= 200 mmBTU/Hour	On and after May 1, 2011	0.04	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1142	Petroleum Refineries - Crude Unit Atmospheric Heater		>= 200 mmBTU/Hour	On and after July 11, 2007	0.04	lb Nox/mmBTU input	24 hr rolling	
DE	Reg. 1112	Boiler	Gas - Face or Tangential Fired	>100 mmBTU/hr not EGU	After May 31, 1995	0.20	lb Nox/mmBTU input		
DE	Reg. 1112	Boiler	Coal - Dry Bottom-Face or Tangential Fired	>100 mmBTU/hr not EGU	After May 31, 1995	0.38	lb Nox/mmBTU input		
DE	Reg. 1112	Boiler	Coal - Dry Bottom-stoker	>100 mmBTU/hr not EGU	After May 31, 1995	0.43	lb Nox/mmBTU input		
DE	Reg. 1112	Boiler	O/Gas - Face or Tangential Fired	>100 mmBTU/hr not EGU	After May 31, 1995	0.25	lb Nox/mmBTU input		
DE	Reg. 1112	Boiler	O/Gas - Cyclone	>100 mmBTU/hr not EGU	After May 31, 1995	0.40	lb Nox/mmBTU input		
DE	Reg. 1112	Boiler	specifies control tech.	>50 & < 100 mmBTU/hr not EGU	After May 31, 1995				

DE	Reg. 1148	Combustion Turbines	Simple or Combined Cycle Gas		After May 1, 2009	42	ppmv corrected to 15% O2	1 hr avg if CEMS	
DE	Reg. 1148	Combustion Turbines	Liquid fuel Simple orCombined Cycle		After May 1, 2009	88	ppmv corrected to 15% O2	1 hr avg if CEMS	
DE	Reg. 1144	Distributed generator	Any fuel - existing units	> 10 MW output with exceptions		4.0	g NOx/MWh output		
DE	Reg. 1144	Distributed generator	Any fuel except waste/landfill/digester gases - new unit after 1/1/2008	> 10 MW output with exceptions	After Jan. 1,2008	1.0**	g NOx/MWh output	Certification of new engine	
DE	Reg. 1144				** The Table in section 3.2.2.1 of the on-line version lists two standards for this new units installed on or after Jan. 1, 2008: 2.2 and 1.0 g NOx/MWh output.				
DE	Reg. 1144	Distributed generator	Any fuel except waste/landfill/digester gases - new unit after 1/1/2012	> 10 MW output with exceptions	After Jan. 1,2012	0.6	g NOx/MWh output	Certification of new engine	
DE	Reg. 1144	Distributed generator	Waste/landfill/digester gases - new unit after 1/1/2008	> 10 MW output with exceptions	After Jan. 1,2008	2.2	g NOx/MWh output	Certification of new engine	
DE	Reg. 1148								
MD	COMAR 26.11.09.08	COMAR 26.11.09.08 covers fuel burning equipment which includes boilers							
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Coal - Tangentially fired (not High Heat Release)	>= 250 mmBTU/hr		0.45	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Coal - Wall fired (not High Heat Release)	>= 250 mmBTU/hr		0.50	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Oil	>= 250 mmBTU/hr		0.30	lb Nox/mmBTU input	30 rolling Avg	

MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Oil/Gas	>= 250 mmBTU/hr			lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Cyclone	>= 250 mmBTU/hr		0.70	lb Nox/mmBTU input	30 rolling Avg	May 1 through Sept 30
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Cyclone	>= 250 mmBTU/hr		1.5	lb Nox/mmBTU input	30 rolling Avg	October 1 through April 30
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Coal - Tangentially fired (High Heat Release)	>= 250 mmBTU/hr		0.70	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Coal - Wall Fired (High Heat Release)	>= 250 mmBTU/hr		0.80	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08C	EGU Fuel Burning Equipment	Coal Cell Burners	>= 250 mmBTU/hr		0.60	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08C	Non-EGU Fuel Burning Equipment		>= 250 mmBTU/hr		0.70	lb Nox/mmBTU input	30 rolling Avg	May 1 through Sept 30
MD	COMAR 26.11.09.08C	Non-EGU Fuel Burning Equipment		>= 250 mmBTU/hr		0.99	lb Nox/mmBTU input	30 rolling Avg	October 1 through April 30
MD	COMAR 26.11.09.08D	Fuel Burning Equipment	Coal Fired	>= 100 & <250 mmBTU/hr		0.50	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08D	Fuel Burning Equipment	Gas only - Tangential or Wall-Fir	>= 100 & <250 mmBTU/hr		0.20	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08D	Fuel Burning Equipment	Gas/Oil - Tangential or Wall-Fire	>= 100 & <250 mmBTU/hr		0.25	lb Nox/mmBTU input	30 rolling Avg	
MD	COMAR 26.11.09.08H	Cement Kiln		<600,000 ton per year capacity		1000	lb Nox/day	30 rolling Avg	
MD	COMAR 26.11.09.08H	Cement Kiln		>=600,000 ton per year capacity		1800	lb Nox/day	30 rolling Avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas Only - Tangential Fired	>250 mmBTU/hr	prior to July 1, 2014	0.20	lb Nox/mmBTU input	CEMS - 24 hour avg	24-hour daily heat input-weighted average NOx emission rates from block hourly arithmetic emission rate average

NY	Subpart 227-2*	Boiler - Very Large	Gas/Oil - Tangential Fired	>250 mmBTU/hr	prior to July 1, 2014	0.25	lb Nox/mmBTU input	CEMS - 24 hour avg	Allows 30-day rolling heat input-weighted average emission rate to demonstrate compliance from October 1st to April 30th
NY	Subpart 227-2*	Boiler - Very Large	Coal Wet Bottom - Tangential Fired	>250 mmBTU/hr	prior to July 1, 2014	1.00	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Dry Bottom - Tangential Fired	>250 mmBTU/hr	prior to July 1, 2014	0.42	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas Only - Wall fired	>250 mmBTU/hr	prior to July 1, 2014	0.20	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas/Oil - Wall fired	>250 mmBTU/hr	prior to July 1, 2014	0.25	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Wet Bottom - Wall fired	>250 mmBTU/hr	prior to July 1, 2014	1.00	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Dry Bottom - Wall fired	>250 mmBTU/hr	prior to July 1, 2014	0.45	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas/Oil - Cyclone	>250 mmBTU/hr	prior to July 1, 2014	0.43	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Wet Bottom - Cyclone	>250 mmBTU/hr	prior to July 1, 2014	0.60	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Dry Bottom - Stoker (when 25 percent of the total content of the fuel combusted, on a Btu basis, includes other solid fuels)	>250 mmBTU/hr	prior to July 1, 2014	0.03	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Dry Bottom - Stoker (when 25 percent of the total content of the fuel combusted, on a Btu basis, includes other solid fuels)	>250 mmBTU/hr	prior to July 1, 2014	0.33	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas Only - Tangential Fired	>250 mmBTU/hr	on or after July 1, 2014	0.08	lb Nox/mmBTU input	CEMS - 24 hour avg	

NY	Subpart 227-2*	Boiler - Very Large	Gas/Oil - Tangential Fired	>250 mmBTU/hr	on or after July 1, 2014	0.15	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Wet Bottom - Tangential Fired	>250 mmBTU/hr	on or after July 1, 2014	0.12	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Dry Bottom - Tangential Fired	>250 mmBTU/hr	on or after July 1, 2014	0.12	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas Only - Wall fired	>250 mmBTU/hr	on or after July 1, 2014	0.08	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas/Oil - Wall fired	>250 mmBTU/hr	on or after July 1, 2014	0.15	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Wet Bottom - Wall fired	>250 mmBTU/hr	on or after July 1, 2014	0.12	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Dry Bottom - Wall fired	>250 mmBTU/hr	on or after July 1, 2014	0.12	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Gas/Oil - Cyclone	>250 mmBTU/hr	on or after July 1, 2014	0.20	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Wet Bottom - Cyclone	>250 mmBTU/hr	on or after July 1, 2014	0.20	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Coal Fluidized bed	>250 mmBTU/hr	on or after July 1, 2014	0.08	lb Nox/mmBTU input	CEMS - 24 hour avg	
NY	Subpart 227-2*	Boiler - Very Large	Other configurations other than those listed above or which are fired primarily with fuels not listed above	>250 mmBTU/hr		Source specific RACT determination			
NY	Subpart 227-2*	Boiler - Large	Gas Only	>100 <250 mmBTU/hr	prior to July 1, 2014	0.20	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested	
NY	Subpart 227-2*	Boiler - Large	Gas/Oil	>100 <250 mmBTU/hr	prior to July 1, 2014	0.30	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested	

NY	Subpart 227-2*	Boiler - Large	Pulverized Coal	>100 & <250 mmBTU/hr	prior to July 1, 2014	0.50	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Coal (Overfeed Stoker) (<25 % total content of the fuel combusted, on a Btu basis, includes other solid fuels)	>100 & <250 mmBTU/hr	prior to July 1, 2014	0.30	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Coal (Overfeed Stoker) (>= 25% total content of the fuel combusted, on a Btu basis, includes other solid fuels)	>100 & <250 mmBTU/hr	prior to July 1, 2014	0.33	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Gas Only	>100 & <250 mmBTU/hr	on or after July 1, 2014	0.06	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Gas/Oil	>100 & <250 mmBTU/hr	on or after July 1, 2014	0.15	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Pulverized Coal	>100 & <250 mmBTU/hr	on or after July 1, 2014	0.20	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Coal	>100 & <250 mmBTU/hr	on or after July 1, 2014	0.08	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Coal (Fluidized Bed when combusting other solid fuels (for example, tire-derived fuel, waste wood) that constitute no more than 30 percent of the total fuel content on a Btu basis)	>100 & <250 mmBTU/hr	on or after July 1, 2014	0.08	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested
NY	Subpart 227-2*	Boiler - Large	Other configurations other than those listed above or which are fired primarily with fuels not listed above	>100 & <250 mmBTU/hr		Source specific RACT determination		
NY	Subpart 227-2*	Boiler - Mid-size boilers	Gas Only	> 25 mm & <100 BTU/hr	prior to July 1, 2014	0.10	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested

NY	Subpart 227-2*	Boiler - Mid-size boilers	Distillate Oil/Gas	> 25 mm & <100 BTU/hr	prior to July 1, 2014	0.12	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested	
NY	Subpart 227-2*	Boiler - Mid-size boilers	Residual Oil/Gas	> 25 mm & <100 BTU/hr	prior to July 1, 2014	0.30	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested	
NY	Subpart 227-2*	Boiler - Mid-size boilers	Gas only	> 25 mm & <100 BTU/hr	on or after July 1, 2014	0.05	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested	
NY	Subpart 227-2*	Boiler - Mid-size boilers	Distillate Oil/Gas	> 25 mm & <100 BTU/hr	on or after July 1, 2014	0.08	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested	
NY	Subpart 227-2*	Boiler - Mid-size boilers	Residual Oil/Gas	> 25 mm & <100 BTU/hr	on or after July 1, 2014	0.20	lb Nox/mmBTU input	CEMS - 24 hour avg or 1-hour avg if stack tested	
NY	Subpart 227-2*	Boiler - Mid-size boilers	Other configurations other than those listed above or which are fired primarily with fuels not listed above	> 25 mm & <100 BTU/hr		Source specific RACT determination			
NY	Subpart 227-2*	Combustion Turbines	Gaseous Fueled simple cycle	>=10 mmBTU/hr	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	50	ppmvd NOx (15% O2 basis)	1-Hour avg during ozone season/30 rolling or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	Combustion Turbines	Gaseous Fueled regenerative combustion turbines	>=10 mmBTU/hr	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	50	ppmvd NOx (15% O2 basis)	1-Hour avg during ozone season/30 rolling or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	Combustion Turbines	Distillate oil or more than one fuel simple cycle	>=10 mmBTU/hr	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	100	ppmvd NOx (15% O2 basis)	1-Hour avg during ozone season/30 rolling or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	Combustion Turbines	Distillate oil or more than one fuel regenerative combustion turbines	>=10 mmBTU/hr	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	100	ppmvd NOx (15% O2 basis)	1-Hour avg during ozone season/30 rolling or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	Combustion Turbines	Combined Cycle - firing gaseous fuel	>=10 mmBTU/hr	prior to July 1, 2014	42	ppmvd NOx (15% O2 basis)	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	Combustion Turbines	Combined Cycle - firing oil	>=10 mmBTU/hr	prior to July 1, 2014	65	ppmvd NOx (15% O2 basis)	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	Combustion Turbines	Other fuels	>=10 mmBTU/hr	prior to July 1, 2014	Source specific RACT determination			
NY	Subpart 227-2*	Combustion Turbines	Other fuels & all GT operating	>=10 mmBTU/hr	on or after July 1, 2014	Source specific RACT determination			

NY	Subpart 227-2*	IC Engines	Natural Gas fueled	>= 200 BHP (Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	1.50	g/bhp-hr	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	IC Engines	Landfill gas/digester gas with/without Natural Gas	>= 200 BHP (Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	2.00	g/bhp-hr	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	IC Engines	Oil fueled	>= 200 BHP (Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	2.30	g/bhp-hr	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	IC Engines	Natural Gas fueled	>= 400 BHP (Outside Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	1.50	g/bhp-hr	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	IC Engines	Landfill gas/digester gas with/without Natural Gas	>= 400 BHP (Outside Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	2.00	g/bhp-hr	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	IC Engines	Oil fueled	>= 400 BHP (Outside Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	2.30	g/bhp-hr	1-Hour avg or if using CEMS - 24 hour avg	
NY	Subpart 227-2*	IC Engines	Other fuels	>= 200 BHP (Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	Source specific RACT determination			
NY	Subpart 227-2*	IC Engines	Other fuels	>= 400 BHP (Outside Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	Source specific RACT determination			
NY	Subpart 227-2*	IC Engines	Any fuel type	>= 200 BHP (Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	Emission limit >= 90 % reduction from 1990 baseline emissions			Alternative emission limit option
NY	Subpart 227-2*	IC Engines	Any fuel type	>= 400 BHP (Outside Severe area)	Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014	Emission limit >= 90 % reduction from 1990 baseline emissions			Alternative emission limit option
NY	Subpart 227-2*	Other combustion installations	Any type	At Major NOX Facility		Source specific RACT determination			

	*6 NYCRR Part 227, Subpart 227-2								
PA	Refer to Volume 44 of the PENNSYLVANIA BULLETIN pages 2392-2404, APRIL 19, 2014 to see the proposed rule section 129.97 (25 Pa. Code §129.97).								
PA	Proposed 25 Pa. Code §129.97(b)	Combustion unit	any	>= 20 mmBTU input					Annual adjustment to or tune-up
PA	Proposed 25 Pa. Code §129.97 (c)	Boiler or other combustion source	any	< 20 mmBTU input					Installation, maintenance and operation of the source in accordance with the manufacturer's specifications and GEPs
PA	Proposed 25 Pa. Code §129.97 (c)	Combustion turbine	any	< 1,000 bhp output					Installation, maintenance and operation of the source in accordance with the manufacturer's specifications and GEPs
PA	Proposed 25 Pa. Code §129.97 (c)	Internal combustion engine	any	< 500 bhp gross					Installation, maintenance and operation of the source in accordance with the manufacturer's specifications and GEPs
PA	Proposed 25 Pa. Code §129.97 (c)	Emergency standby engine	any	< 500 hours in a 12-month rolling period					Installation, maintenance and operation of the source in accordance with the manufacturer's specifications and GEPs
PA	Proposed 25 Pa. Code §129.97(e)	Municipal solid waste landfill	Constructed on or before May 30, 1991			IBR 40 CFR Part 60, Subpart Cc emission guidelines			
PA	Proposed 25 Pa. Code §129.97	Municipal solid waste landfill	Constructed after May 30, 1991,			IBR 40 CFR Part 60, Subpart WWW			
PA	Proposed 25 Pa. Code §129.97(f)	Municipal waste combustor	Constructed on or before September 20, 1994			IBR 40 CFR Part 60, Subpart Cb & applicable plans in 40 CFR Part 62.			
PA	Proposed 25 Pa. Code §129.97	Municipal waste combustor	Constructed after September 20, 1994			IBR 40 CFR Part 60, Subpart Eb			
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit or process heater	Natural gas-fired	>= 50 & <250 mmBTU/hr		0.08	lb Nox/mmBTU input		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit or process heater	Distillate oil-fired	>= 50 & <250 mmBTU/hr		0.12	lb Nox/mmBTU input		

PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit or process heater	Residual oil-fired	>= 50 & <250 mmBTU/hr		0.20	lb Nox/mmBTU input		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit or process heater	Refinery gas-fired	>= 50 & <250 mmBTU/hr		0.25	lb Nox/mmBTU input		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit or process heater	Coal-fired	>= 50 & <250 mmBTU/hr		0.45	lb Nox/mmBTU input		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit	Coal-fired - circulating fluidized bed	>= 250 mmBTU/hr		0.20	lb Nox/mmBTU input		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit	Coal-fired - tangentially fired	>= 250 mmBTU/hr		0.35	lb Nox/mmBTU input		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit	Coal-fired - other	>= 250 mmBTU/hr		0.40	lb Nox/mmBTU input		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion unit	Any other	>= 250 mmBTU/hr		0.40	lb Nox/mmBTU input		
Current regulation §121.1 defines "Combustion unit" as "A stationary equipment used to burn fuel primarily for the purpose of producing power or heat by indirect heat transfer."									
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Natural gas or a noncommercial gaseous fuel - combined cycle or combined heat and power	>= 1000 bhp & <180 MW output		42	ppmvd NOx (15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Fuel Oil - - combined cycle or combined heat and power	>= 1000 bhp & <180 MW output		75	ppmvd NOx (15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Natural gas or a noncommercial gaseous fuel - combined cycle or combined heat and power	>= 1000 bhp & <180 MW output		2	ppmvd VOC (as propane 15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Fuel Oil - - combined cycle or combined heat and power	>= 1000 bhp & <180 MW output		2	ppmvd VOC (as propane 15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Natural gas or a noncommercial gaseous fuel - combined cycle or combined heat and power	>= 180 MW output		4	ppmvd NOx (15% O2 basis)		

PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Fuel Oil - combined cycle or combined heat and power	>= 180 MW output		2	ppmvd NOx (15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Natural gas or a noncommercial gaseous fuel - combined cycle or combined heat and power	>= 180 MW output		2	ppmvd VOC (as propane 15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Fuel Oil - combined cycle or combined heat and power	>= 180 MW output		2	ppmvd VOC (as propane 15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Natural gas or a noncommercial gaseous fuel - simple cycle or regenerative cycle combustion	>= 1000 bhp & <180 MW output		42	ppmvd NOx (15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Fuel oil - simple cycle or regenerative cycle combustion	>= 1000 bhp & <180 MW output		75	ppmvd NOx (15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Natural gas or a noncommercial gaseous fuel - simple cycle or regenerative cycle combustion	>= 1000 bhp & <180 MW output		9	ppmvd VOC (as propane 15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Combustion turbine	Fuel oil - simple cycle or regenerative cycle combustion	>= 180 MW output		9	ppmvd VOC (as propane 15% O2 basis)		
PA	Proposed 25 Pa. Code §129.97(g)	Stationary internal combustion engine	Natural gas - lean burn	>= 500 bhp		3.0	g NOx/bhp-hr		
PA	Proposed 25 Pa. Code §129.97(g)	Stationary internal combustion engine	Natural gas, liquid fuel or dual-fuel - lean & rich burn	>= 500 bhp		0.4	g VOC/bhp-hr		
PA	Proposed 25 Pa. Code §129.97(g)	Stationary internal combustion engine	Liquid fuel or duel fuel - lean burn	>= 500 bhp		8.0	g NOx/bhp-hr		
PA	Proposed 25 Pa. Code §129.97(g)	Stationary internal combustion engine	Natural gas - rich burn	>= 500 bhp		2.0	g NOx/bhp-hr		
PA	Proposed 25 Pa. Code §129.97(g)	Stationary internal combustion engine	Natural gas - rich burn	>= 500 bhp		1.0	g VOC/bhp-hr		
PA	Proposed 25 Pa. Code §129.97(j)	Boilers, Stationary combustion turbines, Stationary internal combustion engines.	Must also comply with §129.201-.205						Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA

PA	Proposed 25 Pa. Code §129.97(j)	Stationary internal combustion engines.	Must also comply with §129.111-.113						
PA	Proposed 25 Pa. Code §129.97(h)	Portland cement kiln	Long wet-process			3.88	lb NOx per ton of clinker produced		
PA	Proposed 25 Pa. Code §129.97(h)	Portland cement kiln	Preheater			2.36	lb NOx per ton of clinker produced		
PA	Proposed 25 Pa. Code §129.97(h)	Portland cement kiln	Precalciner			2.36	lb NOx per ton of clinker produced		
PA	Proposed 25 Pa. Code §129.97(h)	Portland cement kiln	Long dry-process			3.44	lb NOx per ton of clinker produced		
PA	Proposed 25 Pa. Code §129.97(j)	Portland cement kiln	Must also comply with §129.141-.146						
PA	25 Pa. Code §129.201	Boilers	Natural gas or noncommercial gaseous fuel	>= 100 & <250 mmBTU/hr		0.10	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.201	Boilers	Solid or liquid fuel	>= 100 & <250 mmBTU/hr		0.20	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.201	Boilers	Any	>= 250 mmBTU/hr & not subject to CAIR		0.17	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.201	Stationary combustion turbine	Natural gas or a noncommercial gaseous fuel - combined cycle or regenerative cycle	>= 100 & <250 mmBTU/hr		0.17	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	or 1.3 lbs NOx/MWH; Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.202	Stationary combustion turbine	Oil - combined cycle or regenerative cycle	>= 100 & <250 mmBTU/hr		0.26	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	or 2.0 lbs NOx/MWH; Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.202	Stationary combustion turbine	Natural gas or a noncommercial gaseous fuel - simple cycle	>= 100 & <250 mmBTU/hr		0.20	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	or 2.2 lbs NOx/MWH; Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.202	Stationary combustion turbine	Oil - simple cycle	>= 100 & <250 mmBTU/hr		0.30	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	or 3.0 lbs NOx/MWH; Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA

PA	25 Pa. Code §129.202	Stationary combustion turbine	Any	>= 250 mmBTU/hr & not subject to CAIR		0.17	lb Nox/mmBTU input	May 1 to September 30 Emissions Cap	Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.203	Stationary internal combustion engines	Spark-ignited engine	> 1000 hp rating		3.0	g NOx/bhp-hr	May 1 to September 30 Emissions Cap	Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §129.203	Stationary internal combustion engines	Compression ignition - diesel fuel or duel fuel – diesel fuel and natural gas	> 1000 hp rating		2.3	g NOx/bhp-hr	May 1 to September 30 Emissions Cap	Applicable only in Bucks, Chester, Delaware, Montgomery or Philadelphia Counties, PA
PA	25 Pa. Code §§129.201-129.203	Were adopted as measure to attain the 1-hour ozone NAAQS				1.5	g NOx/bhp-hr	May 1 to September 30 Emissions Cap	Applicable to units emitting >153 tons NOX from May 1 to Sept. in any year after 1995
PA	25 Pa. Code §145.113	Stationary internal combustion engines	Rich burn - gas fueled?	>= 2400 bhp rating		3.0	g NOx/bhp-hr	May 1 to September 30 Emissions Cap	Applicable to units emitting >153 tons NOX from May 1 to Sept. in any year after 1995
PA	25 Pa. Code §145.113	Stationary internal combustion engines	Lean Burn - gas fueled?	>= 2400 bhp rating		2.3	g NOx/bhp-hr	May 1 to September 30 Emissions Cap	Applicable to units emitting >153 tons NOX from May 1 to Sept. in any year after 1995
PA	25 Pa. Code §145.113	Stationary internal combustion engines	Diesel fuel or duel fuel	>= 3000 bhp rating		2.3	g NOx/bhp-hr	May 1 to September 30 Emissions Cap	Applicable to units emitting >153 tons NOX from May 1 to Sept. in any year after 1995
PA	25 Pa. Code §145.113	Stationary internal combustion engines	Diesel fuel or duel fuel	>= 4400 bhp rating		2.3	g NOx/bhp-hr	May 1 to September 30 Emissions Cap	
PA	25 Pa. Code §145.143	Portland cement kiln	Long wet-process			3.88	lb NOx per ton of clinker produced	May 1 to September 30 Emissions Cap	
PA	25 Pa. Code §145.143	Portland cement kiln	Long dry-process - preheater			2.36	lb NOx per ton of clinker produced	May 1 to September 30 Emissions Cap	
PA	25 Pa. Code §145.143	Portland cement kiln	Long dry-process - precalciner			2.36	lb NOx per ton of clinker produced	May 1 to September 30 Emissions Cap	
PA	25 Pa. Code §145.143	Portland cement kiln	Long dry-process			3.44	lb NOx per ton of clinker produced	May 1 to September 30 Emissions Cap	
PA	25 Pa. Code §129.304	Glass melting furnace	Container glass furnaces.	PTE >= 50 TPY NOx	January 1, 2012	4	lbs NOx/ton glass pulled	30-day rolling average basis	
PA	25 Pa. Code §129.304	Glass melting furnace	Pressed or blown glass furnaces.	PTE >= 50 TPY NOx	January 1, 2012	7	lbs NOx/ton glass pulled	30-day rolling average basis	
PA	25 Pa. Code §129.304	Glass melting furnace	Fiberglass furnaces.	PTE >= 50 TPY NOx	January 1, 2012	4	lbs NOx/ton glass pulled	30-day rolling average basis	

PA	25 Pa. Code §129.304	Glass melting furnace	Flat glass furnaces.	PTE >= 50 TPY NOx	January 1, 2012	7	lbs NOx/ton glass pulled	30-day rolling average basis	
PA	25 Pa. Code §129.304	Glass melting furnace	All other glass melting furnaces.	PTE >= 50 TPY NOx	January 1, 2012	6	lbs NOx/ton glass pulled	30-day rolling average basis	

Attachment D to EPA's Comments on Proposed Amendments to Chapters 121 and 129 Presumptive RACT for NOx and VOC. [44 Pa.B. 2392, April 19, 2014]

Summary of Proposed §129.97 Presumptive RACT Standards			Example Limits - New Jersey - N.J.A.C. 7:27-19.4, -19.5, -19.7 & -19.8				
Fuel Type/Unit Type	**Emission Limit**	**Units**	**Fuel Type**	**Size Range**	**Emission Lir**	**Units**	**Compliance Date**
Combustion unit or process heater >= 50 mmBTU/hr <250 mmBTU/hr			**Combustion unit - I/C/I boiler or other indirect heat exchanger not at petroleum refinery**				
Natural gas-fired	0.08	lb NOx/mmBTU input	Natural gas only	>= 25 to < 100 mmBTU/hr	0.05	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			Natural gas only	>= 100 mmBTU/hr	0.10	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			Natural gas only	>= 50 mmBTU/hr	0.10	lb NOx/mmBTU input	March 7, 2007*
			Other gaseous fuels (excluding refinery gas)	>= 25 to < 100 mmBTU/hr	0.20	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			Other gaseous fuels (excluding refinery gas)	>= 100 mmBTU/hr	0.20	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
Distillate oil-fired	0.12	lb NOx/mmBTU input	No 2 Fuel Oil	>= 25 to < 100 mmBTU/hr	0.08	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			No 2 Fuel Oil	>= 100 mmBTU/hr	0.10	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			No 2 Fuel Oil	>= 50 to < 100 mmBTU/hr	0.12	lb NOx/mmBTU input	March 7, 2007*
Residual oil-fired	0.20	lb NOx/mmBTU input	other liquid fuels	>= 25 to < 100 mmBTU/hr	0.20	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			other liquid fuels	>= 50 to < 100 mmBTU/hr	0.30	lb NOx/mmBTU input	March 7, 2007*
			other liquid fuels	>= 100 mmBTU/hr	0.20	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			Duel fuel - natural gas/fuel oil - Face Fired	>= 100 mmBTU/hr	0.28	lb NOx/mmBTU input	March 7, 2007*
			Duel fuel - natural gas/fuel oil - Tangential	>= 100 mmBTU/hr	0.20	lb NOx/mmBTU input	March 7, 2007*
			Duel fuel - natural gas/fuel oil - Cyclone	>= 100 mmBTU/hr	0.43	lb NOx/mmBTU input	March 7, 2007*

			Duel fuel - natural gas/fuel oil	>= 25 to < 100 mmBTU/hr	0.12	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			Duel fuel - natural gas/fuel oil	>= 100 mmBTU/hr	0.20	lb NOx/mmBTU input	May 1, 2010/May 1, 2012 *
			May 1, 2010/May 1, 2012 * meant by May 1 2010 for boilers >= 50 mmBTU/hr if no modification was needed otherwise May 1, 2011. Boilers >=25 but <50 mmBTU/hr May 1, 2011 if no modification was needed otherwise May 1, 2012.				
			March 7, 2007* meant through April 30, 2010 if no modification needed, otherwise April 30, 2011.				
Refinery gas-fired	0.25	lb NOx/mmBTU input	Refinery fuel gas and other gaseous fuel	>= 50 mmBTU/hr	0.20	lb NOx/mmBTU input	March 7, 2007*
Coal-fired	0.45	lb NOx/mmBTU input	Coal Dry Bottom - Face Fired	>= 50 to < 100 mmBTU/hr	0.45	lb NOx/mmBTU input	March 7, 2007*
			Coal Dry Bottom - Face Fired	>= 100 mmBTU/hr	0.43	lb NOx/mmBTU input	March 7, 2007*
			Coal Dry Bottom - Tangentially Fired	>= 50 mmBTU/hr	0.38	lb NOx/mmBTU input	March 7, 2007*
			Coal Dry Bottom - Cyclone Fired	>= 50 mmBTU/hr	0.55	lb NOx/mmBTU input	March 7, 2007*
Combustion unit or process heater >= 250 mmBTU/hr			**Combustion unit -EGU Boilers**				
Coal-fired - circulating fluidized bed	0.20	lb NOx/mmBTU input					
Coal-fired - tangentially fired	0.35	lb NOx/mmBTU input	Coal	Any	1.5	lb NOx/Mw-hr output*	May 1, 2015
Coal-fired - tangentially fired	0.35	lb NOx/mmBTU input	Coal	Any	1.5	lb NOx/Mw-hr output*	After December 14, 2012 through May 1, 2015
Coal-fired - other	0.40	lb NOx/mmBTU input	Coal	Any	1.5	lb NOx/Mw-hr output*	May 1, 2015

Coal-fired - other	0.40	lb NOx/mmBTU input	Coal	Any	1.5	lb NOx/Mw-hr output*	After December 14, 2012 through May 1, 2015
			Oil Heavier than No 2	Any	2.0	lb NOx/Mw-hr output*	May 1, 2015
			Oil No 2 or lighter	Any	1.0	lb NOx/Mw-hr output*	May 1, 2015
			Gas	Any	1.0	lb NOx/Mw-hr output*	May 1, 2015
			* These rates can be converted from pounds per million British Thermal Units (lb/mmBtu) emission rates using a typical heat rate of 10,000 Btu/kWh. (Source: http://www.nj.gov/dep/rules/proposals/080408a.pdf -- unofficial copy of NJ's proposed rule).				
Combustion turbine - combined cycle or combined heat and power -			**Combustion turbine - combined cycle**				
Gaseous Fuel	42.00	ppmvd NOx (15% O2 basis)	Gas Fuel	>= 15 MW or HEDD unit	1.0	lb NOx/Mw-hr output	May 1, 2015
Fuel Oil -	75.00	ppmvd NOx (15% O2 basis)	Oil Fuel	>= 15 MW or HEDD unit	1.6	lb NOx/Mw-hr output	May 1, 2015
			Gas Fuel	>= 25 mmBTU/hr	1.3	lb NOx/Mw-hr output	May 20, 2009
			Oil Fuel	>= 25 mmBTU/hr	2.0	lb NOx/Mw-hr output	May 20, 2009
Combustion turbine - combined cycle or combined heat and power - >180 MWoutput			**Combustion turbine - combined cycle**				
Gaseous Fuel	4.00	ppmvd NOx (15% O2 basis)	Gas Fuel	>= 15 MW or HEDD unit	1.0	lb NOx/Mw-hr output*	May 1, 2015
			Gas fuel	>= 25 mmBTU/hr & HEDD Unit	0.15	lb NOx/mmBTU input	May 20, 2009
Fuel Oil -	2.00	ppmvd NOx (15% O2 basis)	Oil Fuel	>= 15 MW or HEDD unit	1.6	lb NOx/Mw-hr output*	May 1, 2015
			Oil Fuel	>= 25 mmBTU/hr & HEDD Unit	0.35	lb NOx/mmBTU input	May 20, 2009
Combustion turbine - simple cycle or regenerative cycle >1000 bhp			**Combustion turbine - simple cycle or regenerative cycle**				

Gaseous Fuel	42.00	ppmvd NOx (15% O2 basis)	Simple Cycle Gas fuel	>= 30 mmBTU/hr	0.20	lb NOx/mmBTU input	until March 7, 2007
			Simple Cycle Gas fuel	>= 25 mmBTU/hr & at NOx budget Source	0.20	lb NOx/mmBTU input	March 7, 2007 through May 19, 2009
			Simple Cycle Gas fuel	HEDD unit	0.2	lb NOx/mmBTU input	May 20, 2009 through April 30, 2015
			Simple Cycle Gas fuel	>= 25 mmBTU/hr & Not at NOx Budget Source	2.20	lb NOx/Mw-hr output*	March 7, 2007 through May 19, 2009
			Simple Cycle Gas fuel	Not HEDD	2.2	lb NOx/Mw-hr output*	After May 20, 2009
			Simple Cycle Gas fuel	>= 15 MW or HEDD unit and commenced operation on or after	1	lb NOx/Mw-hr output*	After May 1, 2015
			Regenerative Cycle - gas fuel	>= 30 mmBTU/hr	0.15	lb NOx/mmBTU input	until March 7, 2007
			Regenerative Cycle - gas fuel	>= 25 mmBTU/hr & at NOx budget Source	0.15	lb NOx/mmBTU input	March 7, 2007 through May 19, 2009
			Regenerative Cycle - gas fuel	HEDD unit	0.35	lb NOx/mmBTU input	May 20, 2009 through April 30, 2015
			Regenerative Cycle - gas fuel	>= 25 mmBTU/hr & Not at NOx Budget Source	2.0	lb NOx/Mw-hr output*	March 7, 2007 through May 19, 2009
			Regenerative Cycle - gas fuel	Not HEDD	1.3	lb NOx/Mw-hr output*	After May 20, 2009
			Regenerative Cycle - gas fuel	>= 15 MW or HEDD unit and commenced operation on or after May 1, 2005	0.75	lb NOx/Mw-hr output*	After May 1, 2015
Fuel Oil -	75.00	ppmvd NOx (15% O2 basis)	Simple Cycle Oil fuel	>= 30 mmBTU/hr	0.4	lb NOx/mmBTU input	until March 7, 2007
			Simple Cycle Oil fuel	>= 25 mmBTU/hr & at NOx budget Source	0.4	lb NOx/mmBTU input	March 7, 2007 through May 19, 2009

			Simple Cycle Oil fuel	HEDD unit	0.4	lb NOx/mmBTU input	May 20, 2009 through April 30, 2015
			Simple Cycle Oil fuel	>= 25 mmBTU/hr & Not at NOx Budget Source	3.0	lb NOx/Mw-hr output*	March 7, 2007 through May 19, 2009
			Simple Cycle Oil fuel	Not HEDD	3.0	lb NOx/Mw-hr output*	After May 20, 2009
			Simple Cycle Oil fuel	>= 15 MW or HEDD unit and commenced operation on or after May 1, 2005	1.6	lb NOx/Mw-hr output*	After May 1, 2015
			Regenerative Cycle - oil fuel	>= 30 mmBTU/hr	0.35	lb NOx/mmBTU input	until March 7, 2007
			Regenerative Cycle - oil fuel	>= 25 mmBTU/hr & at NOx budget Source	0.35	lb NOx/mmBTU input	March 7, 2007 through May 19, 2009
			Regenerative Cycle - oil fuel	HEDD unit	0.35	lb NOx/mmBTU input	After May 20, 2009
			Regenerative Cycle - oil fuel	>= 25 mmBTU/hr & Not at NOx Budget Source	2.0	lb NOx/Mw-hr output*	March 7, 2007 through May 19, 2009
			Regenerative Cycle - oil	Not HEDD	2.0	lb NOx/Mw-hr	After May 20, 2009
			*These output-based emission rates are based on a heat rate of: Combined or Regenerative cycle combustion turbine: Gas: 8700; Oil : 7700 British thermal units per Kilowatt- Simple cycle combustion turbine: Gas: 11000; Oil: 10300 British thermal units per Kilowatt-hour (Btu/KW-hr). (Source: http://www.nj.gov/dep/rules/adoptions/adopt_090420.pdf)				
			Regenerative Cycle - oil fuel	>= 15 MW or HEDD unit and commenced operation on or after May 1, 2005	1.5	lb NOx/Mw-hr output	After May 1, 2015
Stationary internal combustion engine - >-= 500 bhp			**Stationary internal combustion engines**				
Gaseous fuel - lean burn	3.00	g NOx/bhp-hr	lean burn -- gaseous fuel	>= 148 kW output & used to generate electricity	1.5	g/bhp - hr*	'March 7, 2007
			lean burn -- gaseous fuel	>= 500 HP	2.5	g/bhp - hr	March 7, 2007 or earlier

Liquid fuel or duel fuel - lean burn	8.00	g NOx/bhp-hr	lean burn -- duel (gaseous/liquid) fuel	>= 148 kW output & used to generate electricity	2.3	g/bhp - hr	'March 7, 2007
			lean burn -- liquid fuel	>= 500 HP	8.0	g/bhp - hr	March 7, 2007 or earlier
			lean burn -- liquid fuel	>= 148 kW output & used to generate electricity	2.3	g/bhp - hr	'March 7, 2007
Gaseous fuel - rich burn	2.00	g NOx/bhp-hr	rich-burn - gaseous fuel	>= 500 HP	1.5	g/bhp - hr	March 7, 2007 or earlier
			rich-burn - gaseous or liquid fuel	>= 148 kW output & used to generate electricity	1.5	g/bhp - hr	'March 7, 2007
			any	>= 37 kW output	0.9	g/bhp - hr	March 7, 2007**
			level				
			** Applies to new engines installed after or existing engines modified after this date.				
Municipal Waste Combustor/Sold Waste Incinerator			**Municipal Waste Combustor/Sold Waste Incinerator**				
Constructed on or before September 20, 1994			Any	Any	150	ppmvd NOx @7% O2	See Note below**
Mass burn waterwall	205	ppmvd NOx @7% O2	**July 18, 2009 - If compliance is by optimizing the existing NOx air pollution control system without modifying the MSW incinerator; May 1, 2011 - If compliance is by installing a new NOx air pollution control system on an existing MSW incinerator or by physically modifying an existing MSW incinerator.				
Mass burn rotary waterwall	250	ppmvd NOx @7% O2					
Refuse-derived fuel combustor	250	ppmvd NOx @7% O2					
Fluidized bed combustor	180	ppmvd NOx @7% O2					
Construction, modification, or reconstruction is commenced after September 20, 1994							
Any Type	150.00	ppmvd NOx @7% O2					

Summary of Proposed §129.97 Presumptive RACT Standards			**Example Limits - New York - 6 NYCRR Part 227, Subpart 227-2**				
Fuel Type	**Emission Limit**	**Units**	**Fuel Type**	**Size Range**	**Emission Lir**	**Units**	**Compliance Date**
Combustion unit or process heater >= 50 mmBTU/hr <250 mmBTU/hr			**Combustion units <250 mmBTU/hr**				
Natural gas-fired	0.08	lb NOx/mmBTU input	Gas Only	> 100 & =< 250 mmBTU/hr	0.06	lb NOx/mmBTU input	on or after July 1, 2014

			Gas Only	> 100 & =< 250 mmBTU/hr	0.20	lb NOx/mmBTU input	prior to July 1, 2014
			Gas Only	> 25 & =< 100 mmBTU/hr	0.05	lb NOx/mmBTU input	on or after July 1, 2014
			Gas Only	> 25 & =< 100 mmBTU/hr	0.10	lb NOx/mmBTU input	prior to July 1, 2014
Distillate oil-fired	0.12	lb NOx/mmBTU input	Gas/Oil	> 100 & =< 250 mmBTU/hr	0.15	lb NOx/mmBTU input	on or after July 1, 2014
			Gas/Oil	> 100 & =< 250 mmBTU/hr	0.30	lb NOx/mmBTU input	
Distillate oil-fired	0.12	lb NOx/mmBTU input	Distillate Oil/Gas	> 25 & =< 100 mmBTU/hr	0.08	lb NOx/mmBTU input	on or after July 1, 2014
			Distillate Oil/Gas	> 25 & =< 100 mmBTU/hr	0.12	lb NOx/mmBTU input	prior to July 1, 2014
Residual oil-fired	0.20	lb NOx/mmBTU input	Residual Oil/Gas	> 25 & =< 100 mmBTU/hr	0.20	lb NOx/mmBTU input	on or after July 1, 2014
			Residual Oil/Gas	> 25 & =< 100 mmBTU/hr	0.30	lb NOx/mmBTU input	prior to July 1, 2014
Refinery gas-fired	0.25	lb NOx/mmBTU input					
Coal-fired	0.45	lb NOx/mmBTU input	Pulverized Coal	> 100 & =< 250 mmBTU/hr	0.20	lb NOx/mmBTU input	on or after July 1, 2014
			Pulverized Coal	> 100 & =< 250 mmBTU/hr	0.50	lb NOx/mmBTU input	prior to July 1, 2014
			Coal	> 100 & =< 250 mmBTU/hr	0.08	lb NOx/mmBTU input	on or after July 1, 2014
			Coal - Over feed Stoker	> 100 & =< 250 mmBTU/hr	0.30	lb NOx/mmBTU input	prior to July 1, 2014
			Certain Coal fired fluidized bed	> 100 & =< 250 mmBTU/hr	0.08	lb NOx/mmBTU input	on or after July 1, 2014
Combustion unit or process heater >= 250 mmBTU/hr			**Combustion unit >= 250 mmBTU/hr**				
Coal-fired - circulating fluidized bed	0.20	lb NOx/mmBTU input	Coal Fluidized bed	>= 250 mmBTU/hr	0.08	lb NOx/mmBTU input	on or after July 1, 2014
Coal-fired - tangentially fired	0.35	lb NOx/mmBTU input	Coal	>= 250 mmBTU/hr	0.12	lb NOx/mmBTU input	on or after July 1, 2014
			Coal Dry Bottom - Tangential Fired	>= 250 mmBTU/hr	0.42	lb NOx/mmBTU input	prior to July 1, 2014

Coal-fired - other	0.40	lb NOx/mmBTU input	Coal	>= 250 mmBTU/hr	0.12	lb NOx/mmBTU input	on or after July 1, 2014
			Coal Dry Bottom - Wall fired	>= 250 mmBTU/hr	0.45	lb NOx/mmBTU input	prior to July 1, 2014
Coal-fired - other	0.40	lb NOx/mmBTU input	Coal Wet Bottom - Wall/Tangentially Fired	>= 250 mmBTU/hr	0.12	lb NOx/mmBTU input	on or after July 1, 2014
			Coal Wet Bottom - Cyclone	>= 250 mmBTU/hr	0.12	lb NOx/mmBTU input	on or after July 1, 2014
			Coal Wet Bottom - Wall/Tangentially Fired	>= 250 mmBTU/hr	1.00	lb NOx/mmBTU input	prior to July 1, 2014
			Coal Wet Bottom - Cyclone	>= 250 mmBTU/hr	0.60	lb NOx/mmBTU input	prior to July 1, 2014
Distillate oil-fired	0.12	lb NOx/mmBTU input	Gas/Oil - Wall fired	> 250 mmBTU/hr	0.25	lb NOx/mmBTU input	prior to July 1, 2014
			Gas/Oil - Wall fired	> 250 mmBTU/hr	0.15	lb NOx/mmBTU input	on or after July 1, 2014
			Gas/Oil - Cyclone fired	> 250 mmBTU/hr	0.43	lb NOx/mmBTU	prior to July 1, 2014
			Gas/Oil - Cyclone fired	> 250 mmBTU/hr	0.20	lb NOx/mmBTU input	on or after July 1, 2014
Residual oil-fired	0.20	lb NOx/mmBTU input					
Natural gas-fired	0.08	lb NOx/mmBTU input	Gas Only	> 250 mmBTU/hr	0.20	lb NOx/mmBTU input	prior to July 1, 2014
			Gas Only	> 250 mmBTU/hr	0.08	lb NOx/mmBTU input	on or after July 1, 2014
Combustion turbine - combined cycle or combined heat and power -			**Combustion turbines**				
Gaseous Fuel	42.00	ppmvd NOx (15% O2 basis)	Gaseous Fueled simple or regenerative cycle	>=10 mmBTU/hr	50	ppmvd NOx (15% O2 basis)**	**
Fuel Oil	75.00	ppmvd NOx (15% O2 basis)	Distillate oil or more than one fuel simple or regenerative cycle	>=10 mmBTU/hr	100	ppmvd NOx (15% O2 basis)**	**
			Combined Cycle - firing gaseous fuel	>=10 mmBTU/hr	42	ppmvd NOx (15% O2 basis)**	**
Combustion turbine - combined cycle or combined heat and power - >180 MWoutput			Combined Cycle - firing oil	>=10 mmBTU/hr	65	ppmvd NOx (15% O2 basis)**	**
Gaseous Fuel	4	ppmvd NOx (15% O2 basis)	** Limits in effect before July 1, 2014; after July 1, 2014, limits to be determined via source specific RACT determination.				

Fuel Oil -	2	ppmvd NOx (15% O2 basis)
Combustion turbine - simple cycle or regenerative cycle >1000 bhp		
Gaseous Fuel	42.00	ppmvd NOx (15% O2 basis)
Fuel Oil -	75.00	ppmvd NOx (15% O2 basis)
Stationary internal combustion engine - >-= 500 bhp		
Gaseous fuel - lean burn	3.0	g NOx/bhp-hr
Liquid fuel or duel fuel - lean burn	8.0	g NOx/bhp-hr
Gaseous fuel - rich burn -	2.0	g NOx/bhp-hr

Stationary internal combustion engine - >-= 500 bhp				
Natural Gas fueled	>= 200 BHP (Severe area)	1.5	g/bhp-hr	**
Oil fueled	>= 200 BHP (Severe area)	2.3	g/bhp-hr	**
Natural Gas fueled	>= 400 BHP (Outside Severe area)	1.5	g/bhp-hr	**
Oil fueled	>= 400 BHP (Outside Severe area)	2.3	g/bhp-hr	**
**Some date after date of adoption (June 8, 2004) and presumed to be prior to July 1, 2014				

Enclosure 1. One Page Summary of EPA Comments on Proposed Amendments to RACT Emission Limitations. [44 Pa.B. 2392, April 19, 2014]

I. Emission Limits for Certain Coal-fired Units: EPA advises the Board to revise allowable NOx emission limits for coal-fired boilers currently equipped with advanced controls such as selective catalytic reduction/ selective non-catalytic reduction/ammonia injection for those facilities or units which past actual emissions data show lower limits are certainly technically feasible. EPA has identified certain electric generation/cogeneration or fluidized bed boilers that have technology demonstrated to emit far below the proposed emission limits for coal fired combustion units. EPA believes that some lower limit than proposed is RACT for these units.

II. Other Emission Limits: EPA advises the Board to reevaluate the proposed presumptive RACT emission limits against current NOx emission limits currently in effect in other States as required by EPA's guidance on RACT for the 1997 and 2008 ozone NAAQS. EPA is advising that these States' emissions limits, representing recent conclusions by these other states about RACT or which were necessary to reach attainment, need to be considered and evaluated to determine if they are presumptively RACT for any categories of Pennsylvania sources. EPA has surveyed the limits in effect in those adjacent OTR States and provided a summary compilation.

III. Cost-Effectiveness: EPA advises the Board to reevaluate the proposed RACT limits by revising upward the cost effectiveness range to characterize RACT economic reasonableness and not to use a rigid "benchmark" to reject consideration of controls. Rather EPA's guidance is to consider for a source category control technologies whose range of cost effectiveness overlap an average benchmark. A reasonable average could be currently around $3,200 per ton and the upper bound around $5,500 per ton.

IV. Averaging Plans: EPA advises the Board to amend the averaging provisions of proposed section 129.98 to ensure that averaging plans including units inside designated nonattainment areas achieve at least RACT level reductions – excess reductions from outside any designated nonattainment area boundaries cannot be used to offset emissions above allowable RACT emissions inside any designated nonattainment area boundary. Such a change could be to prohibit averaging plans to include units outside each nonattainment area boundary or some other provision that is shown to achieve the same result. This change is necessary to conform to the Clean Air Act under the ruling of the Courts in *NRDC v. EPA*, 571 F.3d 1245 (D.C. Cir. 2009) in which the Court concluded that designated ozone nonattainment areas required to implement RACT must achieve RACT levels reductions inside the nonattainment area.

V. Title V Related: For better translation of rule requirements into Title V permits issued to sources subject to this rule, EPA advises the Board to include affirmative provisions in the rule itself to: (1) mandate that sources not using continuous monitoring systems (CEMS) to monitor compliance with periodic stack tests and parametric monitoring; (2) specify that a permit issued pursuant to proposed section 129.98(i) ensure the listing of "each air contamination source" at a Title V facility includes all NOx emitting sources at that facility; (3) require records be retained for at least 5 years; and (4) incorporate in Section 129.98 to: (a) identify what changes will mandate a change to the RACT averaging permit; (b) include actual start-up and shut-down emissions in compliance demonstrations; and (c) use the term "operating permit" and "operating permit modification" consistently.

VI. EPA recommends other minor editorial changes for clarity.