Regulatory Impact Analysis for Revisions to the Monitoring Provisions for the NOx SIP Call

Rule Citation Number	15A NCAC 02D .1401, 15A NCAC 02D .1402, 15A NCAC 02D .1424, 15A NCAC 02D .1425
Rule Topic:	Revisions to the Monitoring Provisions for the NOx SIP Call
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Impact Summary:	State government: Yes Local government: No Substantial impact: No Private Sector: Yes
Authority:	G.S. 143-215.3(a)(1); 143-215.65; 143-215.66
Necessity:	To permanently amend rules to address revisions by the EPA on the monitoring provisions for the NOx SIP Call and to incorporate the NOx SIP Call budgets into the rules.

I. Executive Summary

The purpose of this document is to provide an analysis detailing the impacts associated with the proposed amendments to 15A NCAC 02D .1400. These amendments were developed to address the provisions for monitoring of the criteria pollutant Nitrogen Oxides (NOx) for non-electric generating units or non-EGUs and the now defunct emissions credit trading program. The rules will continue to allow facilities to use Continuous Emissions Monitoring Systems (CEMS) or an alternative monitoring method option approved by the North Carolina Division of Air Quality (DAQ) Director. In addition, the amendments also add the North Carolina NOx State Implementation Pan (SIP) Call ozone season budgets for both electric generating units (EGU) and non-EGU sources.

II. Background

The U.S. Environmental Protection Agency (EPA) issued the NOx SIP Call on October 27, 1998 (63 FR 57356). The NOx SIP Call was designed to assist areas in attaining the 1979 1-hour ozone National Ambient Air Quality Standards (NAAQS) by reducing the transport of ozone and precursor emissions from upwind states. The EPA developed a cap and trade system for NOx emissions referred to as the Federal NOx Budget Trading Program (NBTP). The NBTP was codified in 40 Code of Federal Regulations (CFR) Part 97. Sources under the NBTP included: 1) Electric generating units (EGUs) greater than 25 megawatts (MW) at both utility and non-utility facilities such as universities and 2) industrial boilers or turbines greater than 250 million Btu (MMBtu) heat input that produce electricity and/or steam for onsite use. These industrial and institutional sources are generally referred to as "non-EGU" sources because they do not sell electricity to the grid. Therefore, their energy usage is process and site specific.

In 2002, the DAQ established requirements for a NOx cap and trade program involving both the EGU and non-EGU sources. It included NOx allocations for each affected source and a total state budget along with a demonstration that North Carolina would achieve the required emission reductions in accordance with timelines set forth in the state's SIP. The non-EGU sources had to demonstrate compliance with the rule beginning in 2004. As part of demonstrating compliance, these sources had to install and operate a CEMS or other approved monitoring methods under the EPA's 40 CFR Part 75 monitoring requirements. The Part 75 monitoring requirements were codified in the DAQ rules under 15A NCAC 2D .1400.

A new federal NOx and sulfur dioxide (SO_2) trading program, called the Clean Air Interstate Rule (CAIR), was promulgated by the EPA in 2005, which replaced the previous NOx SIP Call budget trading program. The CAIR was promulgated to address transport under both the 1997 8-hour ozone and PM2.5 NAAQS. States could choose to implement annual and ozone season NOx reductions through this federal allowance trading program. North Carolina chose to comply by participating in the federal allowance trading program and by "opting-in" non-EGU sources into the program. The CAIR requirements and budgets for the non-EGUs were identical to the NOx SIP Call, and were codified in the DAQ rules under 15A NCAC 2D .2400 in July of 2006.

In subsequent years, the CAIR was remanded without vacatur by the D.C. Circuit, and replaced with the EPA's Cross-State Air Pollution Rule (CSAPR) on August 8, 2011 (76 FR 48208). The CSAPR requires states to improve air quality by reducing EGU emissions crossing state lines and contributing to both ozone and fine particle pollution in other states starting initially in 2012, but implementation did not begin until 2015. The non-EGUs were excluded from the CSAPR NOx budget trading program because the EPA concluded that these sources did not reduce NOx emissions as a result of being included in the previous trading programs and that these sources, as a group, had allowances they did not need for compliance. The first set of emissions requirements under the CSAPR took effect on January 1, 2015. The CAIR provisions expired on February 1, 2016 as a result of the DAQ's periodic review and expiration of existing rules (G.S. 150B-21.3A).

Although the non-EGU sources have no federal requirements to monitor or reduce emissions under the CSAPR, the EPA has stated that the anti-backsliding provisions of 40 CFR 51.905(f) require the provisions of the NOx SIP Call, including the statewide NOx emission budgets for non-EGUs, be maintained. Furthermore, the requirements of the NOx SIP Call continue to be permanent and enforceable, including all state regulations developed to implement the requirements of the NOx SIP Call (77 FR 45259). In a very brief "frequently asked questions" (FAQ) document posted on the agency's CSAPR web site, titled "NOx SIP Call Transition for Large non-EGUs", the EPA states that: (1) CSAPR does not preempt or replace the requirements of the NOx SIP Call, (2) NOx SIP Call budgets remain in place for non-EGUs, and (3) 40 CFR Part 75 monitoring, record keeping and reporting requirements must be retained.[1] As part of this proposal, the DAQ is adding the NOx SIP Call budgets for EGUs and large non-EGUs back into the North Carolina Administrative Code (NCAC), and requiring reporting of NOx emissions to the DAQ for the ozone season.

On March 8, 2019, the EPA finalized revisions to the emission monitoring provisions[2] in the State Implementation Plan that are required under the NOx SIP Call. In this action, the EPA finalized amendments providing states with flexibilities to provide large non-EGUs subject to the NOx SIP Call the option of using methods other than CEMS to demonstrate compliance with the state's NOx SIP Call budget. This option for requesting alternative monitoring for large non-EGUs is also included as part of this proposal.

III. Reason for Rule Change

As required by EPA, the proposed amendments will re-establish the NOx SIP Call statewide ozone season budgets for EGUs and large non-EGUs. The proposed changes are largely administrative in nature and are necessary to satisfy the antibacksliding requirements of 40 CFR Part 51 and facilitate clean-up and synchronization of the approved state and federal requirements.

The DAQ also proposes to adopt rules in 15A NCAC 02D .1400 to allow large non-EGU sources subject to the NOx SIP Call the option to use alternative monitoring methods other than CEMS to track NOx emissions that North Carolina would use to demonstrate compliance with the statewide budget. The amendments to these rules would codify the current practice of allowing large non-EGU sources subject the NOx SIP Call the option to use alternative monitoring methods other than CEMS to determine NOx emissions during the ozone season. Related clarifications and/or cross reference adjustments to other rules may also be needed.

IV. Proposed Rule

The DAQ is proposing amendment to the following rules:

15A NCAC 02D .1401, Definitions, is proposed for amendment to add definitions for "EGU", "Large non-EGU", and "NOx ozone season budget" to the list of definitions.

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[1] Cross-State Air Pollution Rule (CSAPR) Frequently Asked Questions; NOx SIP Call Transition for Large non-EGUs; https://www.epa.gov/sites/production/files/2016-05/documents/fact_sheet_nox_sip_call_transition_for_large_non-egus.pdf
[2] 84 FR 8422, March 8, 2019. U.S. Environmental Protection Agency, Emissions Monitoring Provisions in State Implementation Plans Required Under the NOx SIP Call, Final Rule.

15A NCAC 02D .1402, Applicability, is proposed for amendment to include 15A NCAC 02D .1424 and .1425 to the list of rules that apply statewide.

The DAQ is proposing adoption of the following rules:

15A NCAC 02D .1424, Large Non-Electric Generating Units, is proposed for adoption to include an option for large non-EGUs to request alternative monitoring for determining NOx emissions during the ozone season if they are not required to monitor NOx for another rule.

15A NCAC 02D .1425, NOx SIP Call Budget, is proposed for adoption to provide the NOx ozone season budgets for EGUs and large non-EGUs and to require reporting of the NOx emissions to the DAQ for the ozone season.

V. Estimating the Fiscal Impacts

The sections below provide a summary of the costs associated with complying with the rule for facilities and the cost savings for codifying an alternative monitoring method.

Statewide Ozone Season Budget

Actual ozone season NOx emissions associated with the affected EGUs and large non-EGUs are well below the budgets and this action is not expected to require any additional NOx controls. The addition of the statewide ozone budget into the rules is an administrative change per EPA requirements.

There were originally 14 large non-EGUs that were subject to the NOx SIP Call, but over the years some of the units have been retired. Currently, there are a total of 9 large non-EGUs subject to the NOx SIP Call requirements. Six of these units are power boilers located at paper mills, and three of the units are located at a university. Table 1 has a list of the units and their respective 2019 ozone season NOx emissions. As shown in the table, the large non-EGU sources in North Carolina were 58 percent below the non-EGU NOx SIP call budget in 2019.

For EGUs, there were 32 facilities that were subject to the NOx SIP Call. Since then, many of the EGUs have retired and currently there are only 18 EGU facilities that are still subject to the NOx SIP Call. The 2019 NOx emissions for these sources during the ozone season was 14,127 tons and is 55 percent below the EGU NOx SIP budget. The NOx emissions are expected to decrease in the future as many of the coal-fired EGUs continue to retire.

Table 1. Summary of Large Non-EGUs Subject to the NOx SIP Call in North Carolina

Facility	***2019 Number of Units***	***2019 Ozone Season NOx Emissions (Tons)***
Blue Ridge Paper – Canton	3	701
WestRock – Roanoke Rapids (formerly Kapstone Paper)	1	211
International Paper – New Bern (formally Weyerhaeuser)	2	22
University of North Carolina – Chapel Hill	3	50
Totals	9	984
NOx SIP Call Budget	---	2,329

Alternate NOx Emissions Monitoring Method

The DAQ has identified two alternative NOx emissions monitoring methods that can be used to determine NOx emissions from large non-EGU sources. The first method uses at least five years of historical 40 CFR Part 75 NOx monitoring and flow rate data to determine NOx emissions. The second method uses source test data collected using EPA Methods 1 through 4 to measure flow rate and moisture and EPA Method 7 or 7e to measure NOx concentration prior to the ozone season.

Five of the units listed in Table 1 have already petitioned and have received approval for alternate monitoring procedures pursuant to 15A NCAC 02D .0612 prior to the EPA finalizing the revisions to the emission monitoring provisions in the State Implementation Plan that are required under the NOx SIP Call. Even though five of these units have already petitioned and received approval for alternative monitoring prior to the proposal of these rules, the estimated benefits will be included in this Regulatory Impact Analysis. To estimate the benefit of allowing alternative monitoring, cost data from the Supporting Statement for the Information Collection Request (ICR) Renewal[3] that was developed for the NOx SIP Call was used. In this ICR, the EPA estimated the annual labor, operation and maintenance (O&M), and capital costs for CEMS and alternative monitoring options.

The NOx CEMS and fuel flowmeter and emission factor and fuel flowmeter monitoring options were selected because these are the monitoring systems that are currently being used by the facilities to determine NOx emission in North Carolina. The costs in the ICR were provided in 2017 dollars. To escalate these costs to 2019 dollars, the Employment Cost Index[4] and the Chemical Engineering Plant Cost Index (CEPCI) were used. The ICR stated that the labor costs were based on the June 2017 Current

[3] U.S. Environmental Protection Agency, Rulemaking Docket: EPA-HQ-OAR-2018-0595, Supporting Statement for 2018 NOx SIP Call ICR Renewal corrected 2018-09-27. https://www.regulations.gov/docket/EPA-HQ-OAR-2018-0595/document?documentTypes=Supporting%20%26%20Related%20Material

[4] U.S. Bureau of Labor Statistics, Employment Cost Index, Historical Listing – Volume III, January 2021. https://www.bls.gov/web/eci/echistrynaics.pdf

Employment Cost Index from the U.S. Bureau of Labor Statistics. Using the June 2017 and 2019 Employment Cost Index for Industry, Goods Producing Industries, the escalation factor labor rates was determined to be 1.0692 (136.0/127.2). The escalation factor for other costs using the CECPI was calculated to be 1.0705 (607.5/567.5). Based on these results, an escalation factor of 1.07 will be used to escalate all of the ICR cost values to 2019 dollars for this analysis.

Currently, four of the five units that have been approved for alternative monitoring are using historical 40 CFR Part 75 data, and one unit is using AP-42[5] emission factors and heat rate data to determine NOx emissions. The proposed rules do not include the AP-42 option and the facility will either need to use historical 40 CFR Part 75 data or use EPA Methods 1 through 4 and 7 or 7E prior to the ozone season for the next three ozone seasons. If the facility chooses to incorporate test data collected using EPA Method 1 through 4 and 7 or 7E, then they will incur a cost of $13,093 per year as shown in Table 2 for the next three years. However, this approach is still less costly than operating CEMS at an annual cost of $72, 244 as shown in Table 2. If the facility that chooses to use the historical 40 CFR Part 75 data option, the facility will need to determine NOx concentration and flow rate factors using this historical data. The DAQ assumes that 40 hours of technical hours will be needed to determine these factors at a cost of $3,324. This cost is based on an hourly rate of $83.10, which was derived from the ICR hourly cost of $77.66 for technical personnel and escalated to $2019 using an escalation factor of 1.07. In addition, the DAQ assumed eight managerial hours will be needed to review and approve the factors at a cost of $961. This cost is based on an hourly rate of $120.88, which was derived from the ICR managerial hourly rate of $112.22 and escalated to $2019 using an escalation factor of 1.07. The total cost for determining the NOx concentration and flow rate factors is $4,285. These factors would replace the AP-42 factors and the facility would continue to monitor NOx emissions as they did previously.

The four units already using historical 40 CFR Part 75 data will not experience any new costs from the rule amendment but will continue to receive an annual benefit of $64,817 using an alternative monitoring method rather than CEMS. The remaining four sources that are required to monitor NOx emissions will not have the option to petition for alternative monitoring. These four facilities must operate CEMS to comply with separate federal requirements (40 CFR Part 60, Subpart Db) at an annual cost of $72,244 as shown in Table 2.

As shown in Table 2, the benefit that facilities receive from switching from CEMS to a 40 CFR Part 75 data alternative monitoring option is $64,817 per year for each large non-EGU source. For the facility using AP-42 emission factors, the potential benefit from switching from a NOx CEMS to an EPA test method alternative monitoring method is $59,151 per year for the first three years and $64,817 thereafter. The potential benefit for this facility using AP-42 emission factors to switch to the historical 40 CFR Part 75 data option would be $60,532 in the first year and $64,817 thereafter. It is assumed for this analysis that the facility using AP-42 emission factors will select the 40 CFR Part 75 historical data option for monitoring NOx emission for the proposed rules.

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[5] U.S. Environmental Protection Agency, AP 42, Fifth Edition, Volume I Chapter 1: External Combustion Sources. https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0

Table 2. Annual Cost of CEM and Alternative Monitoring Options

Monitoring Option	*Labor Cost ($2019/year)*	*Operation & Maintenance Cost ($2019/year)*	*Capital/Startup Cost ($2019/year)*	*Total Cost ($2019/year)*
NOx CEMS and Fuel Flowmeter	$33,563	$18,618	$20,063	$72,244
40 CFR Part 75 Emission Factor and Fuel Flowmeter	$3,093	$1,926	$2,408	$7,427
EPA Method 1-4 and 7 or 7E NOx Test Data	$3,093	$0	$10,000 [a]	$13,093
Potential Alternative Monitoring Benefit for Sources Switching from NOx CEMS to 40 CFR Part 75 Data				$64,817
Potential Alternative Monitoring Benefit for Sources Switching from NOx CEMS to EPA Test Method Data				$59,151

[a] Based on stack test cost estimate of $10,000 for performing EPA test methods 1 through 4 and 7 or 7E received from a Practice Manager at TRC.

For eight of the nine large non-EGU units, the codification of these alternative monitoring options will not create any new costs or benefits. One large non-EGU unit will need to switch from using AP-42 emission factors to using either EPA test data or historical 40 CFR Part 75 data to develop concentration and flow rate factors for the unit. Using either of these alternative monitoring options will satisfy the anti-backsliding requirements of 40 CFR Part 51 relative to the state budgets, and facilitate clean-up and synchronization of the approved state and federal requirements.

<u>Annual Reporting</u>

All EGU and non-EGU facilities report monthly NOx emissions to the DAQ either quarterly or biannually. The proposed rule will require the facilities in addition to these reports to also annually report total NOx emissions for the ozone season, which begins on May 1 and ends on September 30. Receipt of this ozone season NOx report is required to be submitted no later than 120 days after the end of the ozone season, which will overlap with one of the current NOx reports submitted by facilities in January each year. Therefore, the facility will not have to submit a separate report to comply with this rule, but provide a separate accounting of the ozone season NOx emissions in their quarterly or biannual report.

To estimate the cost impacts to facilities as a result of the proposed rules, the DAQ used cost information from ICR that was developed for the NOx SIP Call. The ICR estimated hourly rates of $112.22 for managers and $77.66 for technical personnel. The majority of the information collection activities that are included in the ICR are not applicable to the activities that are a result of the proposed rules in this impact analysis, because there are no changes to the monitoring methods used by the facilities to determine NOx emissions. Therefore, only the review of instructions and requirements and the preparation of reports ICR activities were included in this analysis. For reviewing the instructions and requirements, the ICR estimate of four managerial hours and four technical hours were used. This is a one-time cost and will only occur in the first year. For the preparation of the report, the DAQ assumed that the NOx ozone report would be done concurrently with the facility's development of their quarterly or biannual report of monthly NOx emissions. This reduces the impact of developing a separate report for the ozone season. Therefore, we assumed eight hours for technical personnel to prepare the NOx ozone season report and four hours of managerial review. A summary of the facility impacts for non-EGU facilities is provided in Table 3.

Table 3. Non- EGU Facility Impacts

Type of Facility Costs	***Technical Hours***	***Managerial Hours***	***Labor Cost Per Year*** [a]
Read Instructions and Requirements	4	4	$813
Preparation of NOx Ozone Season Report	8	4	$1,145
		Total Facility Cost ($2019)	$1,958
		Total Cost for 4 Non-EGU Facilities in the First Year ($2019)	$7,832
		Total Cost for 4 Non-EGU Facilities in Subsequent Years ($2019)	$4,580

[a] Labor costs obtained from the Supporting Statement for the ICR Renewal developed for the NOx SIP Call. The ICR estimated hourly rates of $112.22 for managers and $77.66 for technical personnel were escalated to $2019 using an escalation factor of 1.07 to get $120.08 and $83.10, respectively.

There are minimal impacts for the EGU sources as a result of the proposed rules. These sources will continue to monitor NOx emissions using CEMS and report NOx emissions to the EPA's Clean Air Markets Division (CAMD). The proposed rules do require that EGU facilities submit a report to the DAQ with their NOx emissions during the ozone season. Again the ozone season report can be done concurrently with other reporting by the facilities to the DAQ, so the same labor estimates for non-EGU facilities were used for all 18 of the EGU facilities. A summary of the facility impacts for non-EGU facilities is provided in Table 4.

<u>State Government Impacts – Permit Modifications</u>

The DAQ will need to modify permits to add the ozone season NOx reporting requirement to the permits for EGUs and large non-EGU sources. This will require the modification and approval of four permits for the affected facilities with non-EGU sources and 18 permits for EGU facilities. This would require a review and modification of the permit by a DAQ permit engineer and the approval of the permit by the DAQ permit supervisor. As described above, there are four facilities that currently operate nine non-EGU sources that are currently monitoring NOx emissions using a CEMS or alternative monitoring determine NOx emissions during the ozone season. It was assumed that the DAQ permit engineer would require eight hours to do the modification and four hours for the DAQ permit supervisor to review and approve the permit. Using these assumptions, the cost impact to the DAQ to modify the permits of 4 non-EGU facilities and 18 EGU facilities would be $14,960 in 2019 dollars. A summary of the hours and costs are provided in Table 5.

Table 4. EGU Facility Impacts

Type of Facility Costs	*Technical Hours*	*Managerial Hours*	*Labor Cost Per Year [a]*
Read Instructions and Requirements	4	4	$813
Preparation of NOx Ozone Season Report	8	4	$1,145
Total Facility Cost ($2019)			$1,958
Total Cost for 18 EGU Facilities in the First Year ($2019)			$35,244
Total Cost for 18 EGU Facilities in Subsequent Years ($2019)			$20,610

Table 5. State Government Costs

State Government Costs	*Permit Review Hours*	*Total Hours [6]*	*Total Compensation ($/hr) [2]*	*Total DAQ Cost*
Permit Review Hours				
Engineer II	8	176	47	$ 8,272
Supervisor	4	88	76	$ 6,688
Total Cost for 4 Non-EGU Facilities and 18 EGU Facilities ($2019)				$ 14,960

Local Community Costs

It is expected that there will be no community impacts as the result of allowing non-EGU sources to use alternative monitoring for the ozone season.

VI. Public Health and Environmental Impact

Nitrogen Oxides are a group of highly reactive gases that form when fuel is burned at high temperatures. These emissions are emitted by industrial sources such as power plants and industrial boilers, as well as on-road and non-road vehicles. Emissions of NOx are a strong oxidizing agent that plays a major role in the atmospheric reactions with volatile organic compounds (VOC) that produce ozone (smog) on hot summer days.

[6] Assumes that 4 non-EGU facilities and 18 EGU facilities would have their permits modified for their sources. [2] To estimate total compensation, the contributing reference rate from the career banding rates for 2018-2019 were used to calculate the annual salary for an Engineer II (16104 Engineer - $63,414) and Supervisor (16106 Engineering Manager - $101,747). See Career-Banding-Rates-2018-19.pdf (nc.gov). Total Compensation is estimated from https://oshr.nc.gov/state-employee-resources/classification-compensation/total-compensationcalculator assuming 10 years of service for the Engineer and 20 years of service for the Supervisor. An estimated 2080 works hours per years was used to calculate the hourly rate.

The DAQ does not expect these methodology changes will have any impact on the air quality of North Carolina. In response to a comment discussing the superiority of CEMS compared to non-CEMS the EPA stated:

> "the superiority of CEMS methodologies for some purposes should not foreclose the possibility of allowing flexibility for NOx SIP Call purposes where other monitoring methods would be sufficient to ensure continued achievement of the Rule's emission reduction requirements." (84 FR 8434)

The changes promulgated by the EPA are intended to change the monitoring requirements for large non-EGU sources and establish NOx ozone season budgets for EGU and large non-EGU sources. The revisions do not change any of the EPA's existing requirements related to statewide NOx emission budgets or enforceable mass emission limits for large EGU and large non-EGU sources. The emissions represented by the nine effected large non-EGU sources represent less than one percent of total NOx emissions. Additionally, this group is not able to expand in number. They are limited in the production of electricity they may potentially generate because they are not allowed to connect to the electric grid and sell electricity on demand. Because these units in 2019 reported NOx emissions more than 50% below the statewide annual budget, the change in methodology for emissions reporting will not trigger an exceedance of the statewide budget. For EGU sources, the annual NOx emissions have been decreasing over the years as the older coal-fired units are replaced with more efficient and less polluting units.

Whether the facilities use CEMS monitoring or a calculation-based approach, the methodology will still be evaluated on standard engineering principles on a case-by-case basis at the time of permit review. A facility's permit will continue to require an annual report of accurate NOx emissions for the ozone season for large non-EGUs.

VII. Cost and Benefit Analysis

The DAQ developed a cost and benefit analysis of the proposed amendments to 15A NCAC 02D .1401 and 15A NCAC 02D .1402 and the proposed adoption of 15A NCAC 02D .1424 and 15A NCAC 02D .1425. The analysis is based on the compliance scenario that is most likely to be pursued by the affected facilities. This analysis uses the cost impacts developed in the previous sections for the private sector and state government.

The fiscal analysis was performed over a 2-year period because all of state government costs occur in the first two years and costs to the private sector are expected to remain constant after the second year of the fiscal analysis. These Year 2 costs will continue for the lifetime of the facility.

The DAQ then calculated the total financial impact for each year by adding the costs and subtracting savings or benefits. Table 6 presents the cash flows and the summation of the impacts. [7] Over the first two

[7] The total impact of the proposed rules over the next 2 years, in 2019-dollar value terms, was calculated by computing the "net present value" of the rule. This calculation allows for an apples-to-apples comparison of future costs and benefits on a common dollar value basis. The method accounts for the "time value of money," the concept that money is worth more in the near term than in the long term because of the capacity to earn interest over time. The present value of a future stream of costs and benefits answers the question, "What is the investment/action

years, the proposed rule would cost the private sector and state government approximately $83,226 in 2019-dollar terms and the benefit from using alternative monitoring would be $319,800 in the first year and $324,085 each year thereafter for the facilities using alternative monitoring.

Table 6. Total Impact Summary of Revisions to 15A NCAC 02D .1400

Cost/Benefits (2019 dollars)	*Year 2022*	*Year 2023*
Non-EGU Sector Costs		
Read Instructions/Prepare Report	$3,252	---
Preparation of NOx Ozone Season Report	$4,580	$7,832
Total Private Sector Non-EGU Costs	$7,832	$7,832
EGU Sector Costs		
Read Instructions/Prepare Report	$14,634	---
Preparation of NOx Ozone Season Report	$20,610	$20,610
Total Private Sector EGU Costs	$35,244	$20,610
State/Local Government Costs		
Permit Modification Review [a]	$7,480	$7,480
Total Government Costs	$7,480	$7,480
Non-EGU Sector Benefits		
Alternative Monitoring	$319,800	$324,085
Total Private Sector Benefits	$319,800	$324,085
Total Cost of Proposed Rulemaking for Private Sector	$43,076	$28,442
Total Cost of Proposed Rulemaking for State/Local Government	$7,480	$7,480
Total Cost of Proposed Rulemaking	$50,556	$35,922
Total Benefit of Proposed Rulemaking for Private Sector	$319,800	$324,085
Total Impact (Costs-Savings)	($269,244)	($288,163)

Net Present Value of Quantified Impacts	($503,323)
Aggregate Impact Analysis	$370,356

[a] Assumes that the DAQ permit modifications occur over Years 2022 and 2023.

VIII. Rule Alternatives

The DAQ is required to analyze alternative approaches under the proposed rulemaking if a substantial economic impact to the government and/or private sector entities is expected to result from the rulemaking. Substantial economic impact is defined in North Carolina's Administrative Procedures Act in NC General Statute 150B-21.4, Fiscal and Regulatory Impact Analysis on Rules as an aggregate financial impact on all persons affected of at least one million dollars in a 12-month period. Because the adoptions and amendments to the 15A 02D .1400 rules do not have a substantial economic impact, no rule alternatives were explored.

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worth to me in today's dollar value equivalent?" Different investments/actions can be accurately compared using their net present values.

IX. Conclusion

Adoption of the alternative monitoring requirements for large non-EGUs codifies the current practice and maintains the associated cost savings for the five eligible facilities. A facility's permit will continue to require an annual report of accurate NOx emissions for the ozone season for large non-EGUs no matter the monitoring methodology approved for reporting.

EGU and non-EGU facilities will incur staff time costs to produce the new annual NOx ozone season report. Year 1 costs total $43,076 with recurring costs of $25,190 annually thereafter.

The DAQ will spend approximately $7,500 in staff time in each of the first two years to complete permit modifications.

These amendments satisfy the anti-backsliding requirements of 40 CFR Part 51 relative to state emission budgets and facilitates clean-up and synchronization of state and federal requirements.

The DAQ does expect not the proposed rule changes will have any impact on the air quality of North Carolina because current NOx emissions are well below the state budgets and these emissions are projected to continue declining.

SECTION .1400 – NITROGEN OXIDES

15A NCAC 02D .1401 DEFINITIONS

(a) For the purpose of this Section, in addition to the definitions in G.S. 143-212, G.S. 143-213, and 15A NCAC 02D .0101, the following definitions shall apply. If a term in this Rule is also defined at 15A NCAC 02D .0101, then the definition in this Rule controls.

(1) "Acid Rain Program" means the federal program for the reduction of acid rain including 40 CFR Parts 72, 75, 76, and 77.

(2) "Actual emissions" means for 15A NCAC 02D .1418, emissions of NOx as measured and calculated pursuant to 40 CFR Part 75, Subpart H.

(3) "Actual heat input" means for 15A NCAC 02D .1418, heat input as measured and calculated pursuant to 40 CFR Part 75, Subpart H.

(4) "Averaging set of sources" means all the stationary sources included in an emissions averaging plan pursuant to 15A NCAC 02D .1410.

(5) "Averaging source" means a stationary source that is included in an emissions averaging plan pursuant to 15A NCAC 02D .1410.

(6) "Boiler" means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

(7) "Combined cycle system" means a system consisting of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

(8) "Combustion turbine" means an enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

(9) "Diesel engine" means a compression ignited two- or four-stroke engine in which liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition.

(10) "Dual fuel engine" means a compression ignited stationary internal combustion engine that is burning liquid fuel and gaseous fuel simultaneously.

(11) "EGU" or electric generating unit means a stationary, fossil fuel-fired boiler or combustion turbine that serves a generator with a nameplate capacity greater than 25 MWe producing electricity for sale at any time, except a large non-EGU.

~~(11)~~(12) "Emergency generator" means a stationary internal combustion engine used to generate electricity only during:

(A) the loss of primary power at the facility that is beyond the control of the owner or operator of the facility; or

(B) maintenance when maintenance is being performed on the power supply to equipment that is essential in protecting the environment or to such equipment itself.

An emergency generator may be operated periodically to ensure that it will operate.

~~(12)~~<u>(13)</u> "Emergency use internal combustion engines" means stationary internal combustion engines used to drive pumps, aerators, and other equipment only during:

(A) the loss of primary power at the facility that is beyond the control of the owner or operator of the facility; or

(B) maintenance when maintenance is being performed on the power supply to equipment that is essential in protecting the environment or to such equipment itself.

An emergency use internal combustion engine may be operated periodically to ensure that it will operate.

~~(13)~~<u>(14)</u> "Excess emissions" means an emission rate that exceeds the applicable limitation or standard; for the purposes of this definition, NOx emitted by a source regulated by 15A NCAC 02D .1418 during the ozone season above its allocation are not considered excess emissions.

~~(14)~~<u>(15)</u> "Fossil fuel fired" means:

(A) For sources that began operation before January 1, 1996, where fossil fuel combusted either alone or in combination with any other fuel, comprises more than 50 percent of the annual heat input on a Btu basis during 1995, or, if a source had no heat input in 1995, during the last year of operation of the unit before 1995;

(B) For sources that began operation on or after January 1, 1996 and before January 1, 1997, where fossil fuel combusted either alone or in combination with any other fuel, comprises more than 50 percent of the annual heat input on a Btu basis during 1996; or

(C) For sources that began operation on or after January 1, 1997:

(i) Where fossil fuel combusted either alone or in combination with any other fuel, comprises more than 50 percent of the annual heat input on a Btu basis during any year; or

(ii) Where fossil fuel combusted either alone or in combination with any other fuel, is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year, provided that the unit shall be "fossil fuel-fired" as of the date, during such year, on which the source begins combusting fossil fuel.

~~(15)~~<u>(16)</u> "Indirect-fired process heater" means an enclosed device using controlled flame where the device's primary purpose is to transfer heat by indirect heat exchange to a process fluid, a process material that is not a fluid, or a heat transfer material, instead of steam, for use in a process.

<u>(17) “Large non-EGU” or large non-electric generating unit means a stationary fossil fuel fired boiler or combustion turbine with a maximum heat input greater than 250 MMBtu/hr which was permitted before October 31, 2000 that either:</u>

<u>(A) does not serve at any time a generator producing electricity for sale; or</u>

(B) serves at any time a generator producing electricity for sale and qualifies under 40 CFR 72.6(b)(4), that addresses certain cogeneration facilities, as an unaffected unit for purposes of the Acid Rain Program.

~~(16)~~(18) "Lean-burn internal combustion engine" means:

a spark ignition internal combustion engine originally designed and manufactured to operate with an exhaust oxygen concentration greater than one percent.

~~(17)~~(19) "NOx" means nitrogen oxides.

(20) "NOx SIP Call control period" for the purposes of the NOx SIP Call budgets in 15A NCAC 02D .1425 means the period May 1 through the end of September 30.

~~(18)~~(21)"Ozone season" means the period beginning ~~May 31 and ending September 30 for 2004 and beginning~~ May 1 and ending September ~~30 for all other years.~~ 30.

~~(19)~~(22) "Potential emissions" means the quantity of NOx that would be emitted at the maximum capacity of a stationary source to emit NOx under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit NOx shall be treated as a part of its design if the limitation is federally enforceable. Such physical or operational limitations include air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed.

~~(20)~~(23) "Projected seasonal energy input" means the maximum design heat input per hour times 3300 hours.

~~(21)~~(24) "Projected seasonal energy output" means the maximum design energy output per hour times 3300 hours.

~~(22)~~(25) "Reasonable assurance" means a demonstration to the Director that a method, procedure, or technique is possible and practical for a source or facility under the expected operating conditions.

~~(23)~~(26) "Reasonably Available Control Technology" or "RACT" means the lowest emission limitation for NOx that a particular source can meet by the application of control technology that is reasonably available considering technological and economic feasibility.

~~(24)~~(27) "Reasonable effort" means the proper installation of technology designed to meet the requirements of 15A NCAC 02D .1407, .1408, or .1409 and the utilization of this technology according to the manufacturer's recommendations or other similar guidance for not less than six months, in an effort to meet the applicable limitation for a source.

~~(25)~~(28) "Rich-burn internal combustion engine" means a spark ignition internal combustion engine originally designed and manufactured to operate with an exhaust oxygen concentration less than or equal to one percent.

~~(26)~~(29) "Seasonal energy input" means the total energy input of a combustion source during the period beginning May 1 and ending September 30.

~~(27)~~(30) "Seasonal energy output" means the total energy output of a combustion source during the period beginning May 1 and ending September 30.

~~(28)~~(31) "Shutdown" means the cessation of operation of a source or its emission control equipment.

~~(29)~~(32) "Source" means a stationary boiler, combustion turbine, combined cycle system, reciprocating internal combustion engine, indirect-fired process heater, or a stationary article, machine, process equipment, or other contrivance, or combination thereof, from which NOx emanate or are emitted.

~~(30)~~(33) "Startup" means the commencement of operation of any source that has shutdown or ceased operation for a period sufficient to cause temperature, pressure, process, chemical, or pollution control device imbalance that would result in excess emissions.

~~(31)~~(34) "Stationary internal combustion engine" means a reciprocating internal combustion engine that is not self-propelled; however, it may be mounted on a vehicle for portability.

(b) Whenever reference is made to the Code of Federal Regulations in this Section, the definitions in the Code of Federal Regulations shall apply unless specifically stated otherwise in a particular rule in this Section.

History Note: *Authority G.S. 143-215.3(a)(1); 143-215.107(a)(5); 143-215.107(a)(7); 143-215.107(a)(10);*
Eff. April 1, 1995;
Temporary Amendment Eff. August 1, 2001; November 1, 2000;
Amended Eff. July 18, 2002;
Readopted Eff. October 1, ~~2020.~~2020;
Amended Eff. XXXX XX, XXXX.

15A NCAC 02D .1402 APPLICABILITY

(a) The rules in this Section do not apply except as specifically set out in this Rule.

(b) The requirements of this Section apply to all sources May 1 through September 30 of each year.

(c) Rules 15A NCAC 02D .1409(c), ~~.1418~~ .1418, .1423, .1424, and ~~.1423~~ .1425 apply Statewide.

(d) Rules 15A NCAC 02D .1407 through .1409(b) and .1413 apply to facilities with potential emissions of NOx greater than or equal to 100 tons per year or 560 pounds per calendar day beginning May 1 through September 30 of any year in the following areas:

(1) Cabarrus County;

(2) Gaston County;

(3) Lincoln County;

(4) Mecklenburg County;

(5) Rowan County;

(6) Union County; and

(7) Davidson Township and Coddle Creek Township in Iredell County.

(e) If a violation of the ambient air quality standard for ozone is measured according to 40 CFR 50.9 in Davidson, Forsyth, or Guilford County or that part of Davie County bounded by the Yadkin River, Dutchmans Creek, North Carolina Highway 801, Fulton Creek and back to Yadkin River, the Director shall initiate analysis to determine the control measures needed to attain and maintain the ambient air quality standard for ozone. By the following May 1, the Director shall implement the specific stationary source control measures contained in this Section that are required as part of the control strategy necessary to bring the area into compliance and to maintain compliance with the ambient air quality standard for ozone. The Director shall implement the rules in this Section identified as necessary by the analysis by notice in the North Carolina Register. The notice shall identify the rules that are to be implemented and shall identify whether the rules implemented are to apply in Davidson, Forsyth, or Guilford County or that part of Davie County bounded by the Yadkin River, Dutchmans Creek, North Carolina Highway 801, Fulton Creek and back to Yadkin River or any combination thereof. At least one week before the scheduled publication date of the North Carolina Register containing the Director's notice implementing rules in this Section, the Director shall send written notification to all permitted facilities within the county where the Rules are being implemented that are or may be subject to the requirements of this Section, informing them that they are or may be subject to the requirements of this Section. For the purposes of notifying permitted facilities in Forsyth County, "Director" means the Director of the Forsyth County local air pollution control program. Compliance shall be determined by 15A NCAC 02D .1403.

(f) If a violation of the ambient air quality standard for ozone is measured according to 40 CFR 50.9 in Durham County, Wake County, or Dutchville Township in Granville County, the Director shall initiate analysis to determine the control measures needed to attain and maintain the ambient air quality standard for ozone. By the following May 1, the Director shall implement the specific stationary source control measures contained in this Section that are required as part of the control strategy necessary to bring the area into compliance and to maintain compliance with the ambient air quality standard for ozone. The Director shall implement the rules in this Section identified as necessary by the analysis by notice in the North Carolina Register. The notice shall identify the rules that are to be implemented and shall identify whether the rules implemented are to apply in Durham County, Wake County, or Dutchville Township in Granville County or any combination thereof. At least one week before the scheduled publication date of the North Carolina Register containing the Director's notice implementing 15A NCAC 02D .1407 through .1409(b) and 15A NCAC 02D .1413, the Director shall send written notification to all permitted facilities within the county where the Rules are being implemented that are or may be subject to the requirements of this Section, informing them that they are or may be subject to the requirements of this Section. Compliance shall be according to 15A NCAC 02D .1403.

(g) If the State nonattainment plan for ozone has failed to attain the ambient air quality standard for ozone in 40 CFR 50.9 and does not qualify for an extension of the attainment date in the Charlotte-Gastonia-Rock Hill ozone nonattainment area, the rules in this Section shall apply to facilities in Cabarrus, Gaston, Lincoln, Mecklenburg, Rowan, and Union Counties and Davidson and Coddle Creek townships in Iredell County with the potential to emit at least 50 tons of NOx per year. Once the nonattainment plan for ozone has failed and the area does not qualify for an extension of the attainment date, the Director shall notice the applicability of these Rules to those sources in the North Carolina Register and shall send written notification to all permitted facilities within the counties where the Rules are being implemented that are or may be subject to the requirements of this Section, informing them that they are or may be subject to the requirements of this Section. For the purposes of notifying permitted facilities in Mecklenburg County, "Director" means the Director of the Mecklenburg County local air pollution control program. Compliance shall be according to 15A NCAC 02D .1403.

(h) Regardless of any other statement of applicability of this Section, this Section does not apply to any:

(1) source not required to obtain an air permit pursuant to 15A NCAC 02Q .0102 or is an insignificant activity as defined in 15A NCAC 02Q .0103;
(2) incinerator or thermal or catalytic oxidizer used primarily for the control of air pollution;
(3) emergency generator;
(4) emergency use internal combustion engine; or
(5) stationary internal combustion engine less than 2400 brake horsepower that operates no more than the following hours between May 1 and September 30:
   (A) for diesel engines:
   $$t = \frac{833{,}333}{ES}$$
   (B) for natural gas-fired engines:
   $$t = \frac{700{,}280}{ES}$$
   where t equals time in hours and ES equals engine size in horsepower.

History Note: *Authority G.S. 143-215.3(a)(1); 143.215.107(a)(5); 143.215.107(a)(7); 143.215.107(a)(10);*
Eff. April 1, 1995;
Amended Eff. April 1, 1997; July 1, 1995; April 1, 1995;
Temporary Amendment Eff. November 1, 2000;
Amended Eff. April 1, 2001;

Temporary Amendment Eff. August 1, 2001;
Amended Eff. June 1, 2008; July 1, 2007; March 1, 2007; July 18, 2002;
Temporary Amendment Eff. December 31, 2008;
Temporary Amendment expired September 29, 2009;
Amended Eff. January 1, 2010;
Readopted Eff. October 1, ~~2020.~~2020;
Amended Eff. XXXX XX, XXXX.

15A NCAC 02D .1424 LARGE NON-ELECTRIC GENERATING UNITS

(a) General requirements. The owner or operator of a large non-EGU shall comply with the monitoring, recordkeeping and reporting requirements in 15A NCAC 02D .0600, with the exception of .0604 and .0612, and shall maintain all records necessary for determining compliance with all applicable limitations and standards of this Section for five years.

(b) The owner or operator of a large non-EGU covered by this Rule may request alternative monitoring procedures if the source is not required by 15A NCAC 02D .1418 or any other federal regulation to comply with 40 CFR Part 75.

(c) For a source subject to 40 CFR Part 60 Subpart D or Subpart Db, the source shall determine NOx mass emissions using the NOx emission rate, total heat input derived, and time interval from each type of fuel during the NOx SIP Call control period.

(d) For a large non-EGU requesting an alternative monitoring procedure, one of the following monitoring options shall be used to determine NOx emissions.

(1) For sources with at least five years of historical CEMS operational data, the NOx mass emissions shall be determined using:

(A) the average NOx concentration of the unit as demonstrated by previous 40 CFR Part 75 monitoring;

(B) the average flow rate of the unit under normal operating conditions as demonstrated by previous 40 CFR Part 75 monitoring; and

(C) the total operating time.

(2) For sources without historical CEMS operational data, the source shall test utilizing 40 CFR Part 60, Appendix A, Methods 1-4 and 7 or 7e to determine NOx concentration and flow rate factors prior to the ozone season for three years.

(A) The NOx concentration and flow rate factors determined from the testing and the number of hours operated during the ozone season will be used to determine NOx emissions for that ozone season.

(B) After a total of three years of testing, the source shall use the average NOx concentration and flow rate factors for subsequent ozone season NOx emissions reporting.

(e) If the approved alternative monitoring or reporting requirements differ from those specified in a corresponding rule in Subchapters 02D or 02Q of this Chapter, the permit shall contain conditions stating the monitoring or reporting requirements.

History Note: Authority G.S. 143-215.3(a)(1); 143-215.65; 143-215.66; 143.215.107(a)(5); 143.215.107(a)(7); 143.215.107(a)(10);
Eff. XXXX XX, 2021.

15A NCAC 02D .1425 NOX SIP CALL BUDGET

(a) This Rule establishes general provisions and reporting requirements for the NOx SIP Call control period budgets pursuant to 40 CFR 51.121 through 51.122.

(b) The owner or operator of an EGU or large non-EGU as defined in 15A NCAC 02D .1401 shall submit a report to the Division no later than 120 days after the NOx SIP Call control period listing the NOx emissions from these sources during the NOx SIP Call control period. The NOx emissions in this report shall be determined in accordance with Part 75 for EGUs and in accordance with 15A NCAC 02D .1424 for large non-EGUs.

(c) The information provided by the EGU and large non-EGU sources will be used to evaluate state level NOx budgets in Paragraph (d) of this Rule. The sum of the tons of NOx emitted from all such units in each control period beginning after the effective date of this rule shall not exceed this budget amount.

(d) For North Carolina's NOx Budget Program, the following budgets shall apply:

(1) The total NOx SIP Call control period budget for EGUs is 31,212 tons; and

(2) The total NOx SIP Call control period budget for large non-EGUs is 2,329 tons.

History Note: Authority G.S. 143-215.3(a)(1); 143-215.65; 143-215.66; 143.215.107(a)(5); 143.215.107(a)(7); 143.215.107(a)(10);
Eff. XXXX XX, 2021.