Attachment E

North Carolina Division of Air Quality’s Review of Integrated Planning Model Results Based on NEEDS v5.14 used in EPA's Revised Air Quality (AQ) Transport Modeling Assessment for 2017

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North Carolina Department of Environment and Natural Resources

Pat McCrory
Governor

Donald R. van der Vaart
Secretary

June 9, 2015

Reid Harvey
USEPA Headquarters
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N. W.
Mail Code: 6204M
Washington, DC 20460

Subject: Review of Integrated Planning Model Results Based on NEEDS v5.14

Dear Mr. Harvey:

This letter summarizes concerns the Division of Air Quality (DAQ) has with the most recent release of the Integrated Planning Model (IPM) results (based on NEEDS v5.14) for North Carolina. We appreciate that the US Environmental Protection Agency (EPA) incorporated the majority of the DAQ's comments submitted on NEEDS v5.13. However, this new model forecasts summer season emissions of nitrogen oxides (NOx) in 2018 which are 34% higher (5,617 tons) than the previous model forecast using NEEDS v5.13. Secondly, the new 2018 forecast is 29% higher (4,607 tons) in summer season NOx emissions relative to actual emissions in 2014. The new modeling results are significantly different from what the DAQ expected after the EPA incorporated our comments into the NEEDS v5.14 database. Therefore, we conducted a detailed review of the new model results. This review identified critical issues that we are asking the EPA to address.

Our concern is that the new IPM forecast does not accurately reflect current and future trends in the generation mix for North Carolina. This incorrect modeling of some of our coal and natural gas plants results in significant increases in NOx emissions relative to the previous modeling forecast. The new model forecasts that coal will provide 84% of the fossil fuel base load electricity generation in 2018, which is a significant shift from current day operations where coal only provides 67% of the fossil fuel base load generation. Since 2011, Duke Energy has built 2,782 megawatts (MW) of natural gas combined cycle units and these units are all operating at approximately 60% of their annual capacity. In addition, Duke Energy recently provided the DAQ with its latest forecast out to 2030 and it does not indicate an increase in coal use, but rather a steady decline in coal generation. The DAQ has also identified errors in the assumptions and input data for three coal-fired plants (GG Allen, Marshall, and Roxboro) and four natural gas combined cycle plants (Lee, Sutton, Rosemary and Butler Warner). We explain both the fuel mix issues and the plant-specific errors in greater detail in the attachment to this letter.

As you know, it is important to get the modeling right to support informed policy decisions regarding North Carolina's "Good Neighbor" status. We trust that the EPA will address our comments as it finalizes its transport modeling for North Carolina.

Note we have also submitted this letter and attachment to the EPA Power Sector modeling website. If you have any questions regarding this submittal, please contact Paula Hemmer of my staff at (919) 707-8708.

Sincerely,

Sheila C Holman

Sheila C. Holman, Director
Division of Air Quality, NCDENR

SCH/pmh

Attachments

cc: Michael Abraczinskas, DAQ
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Attachment

Summary of North Carolina Division of Air Quality Issues with IPM-NEEDS v5.14

The North Carolina Division of air Quality (DAQ) has serious concerns with the 2017/2018 Integrated Planning Model-National Electric Energy Data System version 5.14 (IPM-NEEDs v5.14) forecast. The model forecasts that coal will provide 84% of the fossil fuel base load electricity generation in 2018. This is a significant shift back to coal from actual 2014 levels where coal only provided 67% of the fossil fuel base load generation. The EPA's preliminary air quality modeling analysis based on IPM-NEEDS v5.13 showed that North Carolina does not have any linkages to another states attainment or maintenance issues for the 2008 ozone NAAQS.[1] However, the revised IPM-NEEDS v5.14 analysis shows a 34% increase in summer season emissions in 2018 of nitrogen oxides (NOx) from the previous version, IPM-NEEDS v5.13. For this reason the DAQ has concerns that if the EPA uses the IPM-NEEDS v5.14 forecast in its final air quality modeling analysis it may inappropriately represent the expected emissions from the electricity generating unit (EGU) sector.

The DAQ staff reviewed the IPM-NEEDS v5.14 documentation and data files and held two separate calls with EPA technical staff in an effort to understand what is driving the model results. This information has been helpful for understanding specific issues with the modeling assumptions, input data and results. This summary presents our analysis of each of the issues and provides technical information that shows that the IPM-NEEDS v5.14 forecast is deficient in several ways. We trust that the EPA will consider revising the IPM-NEEDS forecast for North Carolina to address our comments and concerns with the current IPM-NEEDS v5.14 results.

The following key issues are addressed in this attachment:

1. Information that the DAQ has compiled showing that the IPM-NEEDS v5.14 generation forecast does not accurately reflect North Carolina's coal and natural gas generation mix in 2017/2018 and beyond.

2. Technical corrections for the following plants as summarized below:

    a. Roxboro Units 1, 2, 3A, 3B, 4A, and 4b: The EPA accidentally revised the heat rates at these coal-fired units to 14,900 Btu/kWh based on comments pertaining to a wood fired unit located in Roxboro, NC. These units originally had heat rates ranging between from 10,051 Btu/kWh and 10,352 Btu/kWh.

    b. GG Allen Units 3 and 4: Based on an EPA analysis, these units are assumed to not operate the existing selective non-catalytic reduction (SNCR) NOx controls. The EPA indicates in the incremental change document that the controls were "turned off". It is not clear to the DAQ how this change was implemented but it causes many downstream issues with the forecast including 1) retrofitting these units with selective catalytic reduction (SCR), 2) significantly increasing generation at these units, and 3) retiring coal-fired units at other facilities. The model did not, however, adjust the NOx emission rate as expected from the SCR retrofit. <u>It still uses the uncontrolled rate of 0.36 pound per million British thermal units (lb/MMBtu), which results in high NOx emissions at this facility</u>.

[1] Memo from Stephen D. Page, Director, Office of Air Quality Standards to Regional Air Division Directors, USEPA, Information on the Interstate Transport "Good Neighbor" Provision for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) under Clean Air Act (CAA) Section 110(a)(2)(D)(i)(I), January 22, 2014.

c. Marshall Units 1 and 2: The IPM forecast retires these units as a result of the SCR retrofit at GG Allen. According to Duke Energy's May 19, 2015 forecast, these coal units will not be retired.

d. Natural gas combined cycle (NGCC) units at HF Lee, Rosemary, Butler-Warner and LV Sutton: The incremental change spreadsheet indicated that changes were made to these units based on comments provided for the proposed Clean Power Plan Rule. However, it is not clear that changes were actually made to the NEEDS v5.14 input file.

The DAQ's analysis and comments regarding these issues are presented on the following pages.

1. Generation Mix Forecast for 2018

a. Duke Energy has shared with the DAQ its most recent in-house forecast for fuel use and emissions at its facilities in North Carolina. A summary of these data is presented in Table 1 along with EPA historical data and the IPM-NEEDS v5.14 forecast[2]. The Duke Energy data show that coal use has significantly declined from 2011 through 2014 and is forecasted to continue to decline through 2018. On the other hand, natural gas generation has significantly increased from 2011 through 2014 and is forecast to continue to increase through 2018. The IPM-NEEDS v5.14 forecast shows coal generation to be 49% higher and natural gas generation to be 58% lower than the Duke forecast for 2018. It is unclear why the IPM-NEEDS v5.14 forecast is over predicting coal and under predicting natural gas generation in 2018 for North Carolina. The EPA staff has suggested that the IPM-NEEDS v5.14 forecast is most likely driven by fuel prices; however, if this is the case the DAQ suggests that IPM is not accurately capturing other key drivers that are causing a significant shift in North Carolina's generation mix from coal to natural gas. In conclusion, we believe there is a significant flaw in the IPM coal forecast which needs to be corrected before these data are used for National Ambient Air Quality Standards (NAAQS) modeling.

Table 1. Historical and Forecast Heat Input Data from EPA-IPM and Duke Energy (billion Btu (GBtu))

Plant Type*	EPA Historical AMPD			Duke Energy Forecast (May 19, 2015)						IPM - v5.13	IPM - v5.14	IPM v5.14 - Duke Percent Difference
	2011	2013	2014**	2017	2018	2019	2023	2025	2030	2018	2018	2018
Coal	578,915	453,553	482,285	458,004	412,250	379,065	411,309	378,169	353,738	556,200	612,528	49%
NGCC	59,628	181,717	195,429	206,489	215,508	227,149	151,856	141,804	141,430	233,913	91,036	-58%
CT-Gas	29,586	19,080	22,115	11,301	10,111	14,293	7,207	4,838	6,448	7,556	6,462	-36%
CT-Oil	362	177	1,470	3	4	4	0	0	0	0	0	
Total	668,491	668,491	701,299	675,797	637,873	620,511	570,372	524,811	501,616	824,269	710,026	

* CT = combustion turbine.

** Note that relative to 2013, 2014 had increased use of coal and oil due to natural gas curtailment in January of 2014.

b. Utilities in North Carolina have invested substantial amounts of capital to retire coal units and build new efficient NGCC units. In the last four years, Duke Energy has retired 3,003 megawatts (MW) of coal-fired and built 2,782 MW of NGCC as shown in Table 2 on the following page. In 2014, the new NGCC units owned by Duke Energy generated over 17 million megawatt-hours (MWh) of electricity, which represents 23% of total fossil fuel based electricity generation.

Table 2. New NGCC Capacity, 2014 AMPD Generation, and IPM-NEEDS v5.14 2018 Generation

NGCC Facility	Capacity (MW)	2014 AMPD Generation (GWh)	Duke Energy Forecast 2018 Generation (GWh)	IPM v5.14 2018 Generation (GWh)
Buck	620	3,822	4,400	2,226
Dan River	620	3,938	4,563	1,868
L V Sutton	622	3,902	5,062	2,129
H F Lee	920	5,932	7,200	3,082
Total	**2,782**	**17,503**	**21,225**	**9,305**

[2] Note that the EPA's historical Air Markets Program Data (AMPD) data and IPM-NEED v5.14 forecast data include additional units which are owned by companies other than Duke Energy. The non-Duke Energy units represent only 15% of the coal and natural gas use at electricity generating units (EGUs) in North Carolina.

Duke Energy announced on May 19, 2015 that it will be retiring its 376 MW coal-fired plant located in Asheville, NC and replacing it with a 650 MW natural gas-fired plant (http://www.duke-energy.com/news/releases/2015051901.asp). The new plant is expected to begin operating in 2020. The announcement of this new natural gas-fired plant further strengthens the DAQ's argument that North Carolina is transitioning to natural gas as a fuel for its base load fleet at a rapid pace between 2011 and 2020.

In conclusion, IPM is severely under predicting natural gas utilization in North Carolina which must be corrected before the forecasts are used for NAAQS modeling.

c. NGCC units owned and operated by Duke Energy and Southern Company are currently being operated as base load units rather than peaking units. Table 3 and Table 4 present the average annual capacity factors from the EPA AMPD 2013 data and average daily capacity factors from 2013, respectively. The average daily capacity factor was calculated for each month and also for the whole year to show the seasonal variation in utilization. The tables show that the NGCC units currently have annual capacity factors of approximately 60% and average daily capacity factors of 60% to 80% when they are operated. Note that L V Sutton only operated 3 months of the year in 2013.

Table 3. EPA AMPD 2013 Average Annual Capacity Factor for NGCC Units

Facility	Unit ID	Max Capacity Input (MMBtu/hr)	2013 Heat Input	2013 Annual Capacity Factor
Buck	11C	2,604	14,854,704	65%
Buck	12C	2,604	15,253,836	67%
Dan River	8C	2,604	14,141,456	62%
Dan River	9C	2,604	14,281,501	63%
H F Lee	01A	2,701	15,648,873	66%
H F Lee	01B	2,701	15,443,424	65%
H F Lee	01C	2,701	15,677,503	66%
L V Sutton	01A	2,717	2,433,165	10%
L V Sutton	01B	2,717	2,308,795	10%
Richmond County Plant	7	1,980	13,373,594	77%
Richmond County Plant	8	1,980	13,253,364	76%
Richmond County Plant	9	2,540	15,756,155	71%
Richmond County Plant	10	2,540	16,401,619	74%
Plant Rowan County	4	1,875	9,936,613	60%
Plant Rowan County	5	1,875	9,378,816	57%

Table 4. EPA AMPD 2013 Average Daily Capacity Factor by Month for NGCC Units

Facility Name	Unit ID	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year Average
Buck	11C						72%	71%	75%	75%	70%	69%	68%	72%
Buck	12C	70%	77%	76%	68%	69%	69%	73%	74%	73%	72%	68%	66%	71%
Dan River	8C	69%	76%	74%	72%	63%	64%	66%	75%	73%	75%	73%	66%	70%
Dan River	9C	71%	75%	72%	72%	63%	65%	66%	75%	73%	75%	72%	66%	70%
H F Lee	01A	73%	79%	88%	73%	71%	75%	76%	76%	73%	82%	83%	77%	77%
H F Lee	01B	76%	80%	88%	70%	72%	76%	80%	80%	73%	82%	81%	78%	78%
H F Lee	01C	67%	78%	84%	70%	72%	75%	80%	79%	73%	81%	82%	76%	76%
L V Sutton	01A										48%	66%	75%	63%
L V Sutton	01B										55%	64%	71%	63%

Facility Name	Unit ID	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year Average
Plant Rowan	4	70%	75%	78%	75%	69%	62%	67%	53%	68%	67%	70%	68%	68%
Plant Rowan	5	68%	79%	79%	69%	66%	65%	68%	78%	63%	68%	61%	68%	69%
Richmond	7	77%	89%	89%	80%	83%	84%	78%	82%	83%	82%	89%	87%	83%
Richmond	8	81%	88%	89%	76%	85%	82%	77%	83%	79%	74%	87%	86%	82%
Richmond	9	76%	86%	78%	80%	77%	72%	83%	81%	81%	86%	78%	77%	80%
Richmond	10	81%	75%	82%	78%	80%	76%	83%	80%	81%	84%	87%	78%	81%

d. Cost of Natural Gas vs Coal: The IPM-NEEDS v5.14 base case indicates that the cost of coal in 2018 for the S_VACA region averages to approximately $3.65 per MMBtu while the cost of natural gas in the region is $5.77 per MMBtu. Table 5 presents the total fuel use in trillion Btu (TBtu) and average fuel cost in $/MMBtu. It is our understanding that the IPM-NEEDS v5.14 base case assumes that due to a short term increase in the cost of natural gas relative to coal in 2018, Duke Energy would ramp up the use of coal-fired units located in North Carolina.

Table 5. IPM-NEEDS 5.14 Total Fuel Consumption and Average Fuel Cost

Fuel Type	2016	2018	2020	2025	2030	2040	2050
Total Fuel Consumption in TBtu							
Coal	772	849	742	860	813	737	853
Natural Gas	279	141	235	223	325	761	1,179
Average of Fuel $/MMBtu							
Coal	3.62	3.65	3.68	3.87	4.09	4.57	5.34
Natural Gas	5.00	5.77	5.33	6.51	6.94	8.00	10.25

The DAQ does not anticipate this projected price change would impact the dispatch of natural gas units in North Carolina for several reasons. First, Duke Energy does not indicate a shift back to coal generation in its forecast between now and 2030. Second, Duke Energy has plans to build an additional NGCC plant in North Carolina as discussed previously. And lastly, a new 550-mile natural gas pipeline is being built in eastern North Carolina, the Atlantic Coast Pipeline (https://www.dom.com/corporate/what-we-do/atlantic-coast-pipeline). This new pipeline is owned in part by Duke Energy. It will deliver approximately 1.5 billion cubic feet of gas per day from the Marcellus region to North Carolina. It is expected to begin delivering gas in late 2018, according to a project schedule published on May 20, 2015. This increase in natural gas supply to North Carolina will help to stabilize natural gas prices in the future.

e. Net Electricity Imports vs Exports: The IPM-NEEDS v5.14 base case also forecasts that North Carolina would become a net exporter of electricity in 2016. Table 6 shows the imports and exports for each model year as given in the EPA's Incremental Change document for IPM-NEEDS v 5.14. However, according to Energy Information Administration (EIA) data, North Carolina typically imports electricity as shown in Table 7. North Carolina questions the IPM-NEEDS v5.14 base case results that significantly increase coal generation in our state to support the export of electricity. Secondly, Duke Energy's forecast does not indicate an increase in generation from coal or NGCC in our state.

Table 6. Imports and Exports in MW from IPM Base Case using NEEDS 5.14

Region Group	Reserve Constraint	2016	2018	2020	2025	2030	2040	2050
IMPORTS (in MW)								
SERC_VACAR	Winter	0	0	0	0	122	0	0
SERC_VACAR	Summer	156	0	398	1492	1492	1293	1293
SERC_VACAR	Annual	0	0	0	0	0	0	0
EXPORTS (in MW)								
SERC_VACAR	Winter	0	0	0	0	0	0	0
SERC_VACAR	Summer	665	665	1165	665	112	0	0
SERC_VACAR	Annual	0	0	0	0	0	0	0

Table 7. EIA - North Carolina Total Electricity Consumption and Generation

	Thousand MWh		
	2012	2013	2014
Consumption	128,085	129,780	132,816
Generation	116,682	125,952	128,919
% Imported	9.8%	3.0%	3.0%

f. Retirement of Tennessee Valley Authority (TVA) Coal Units: In a conversation with EPA IPM staff, the EPA staff suggested that the IPM model may be shifting some coal capacity associated with the retirement of TVA units to North Carolina EGUs. The units which are to be retired are given below in Table 8 based on the information contained in the EPA's Incremental Change excel file. No retirement dates were specified in the comments. However, these units are expected to retire by 2016 prior to when the Mercury and Air Toxics Standard (MATS) Rule goes into effect (See http://www.eia.gov/todayinenergy/detail.cfm?id=15491).

Given that TVA coal units are not located within the VACAR grid region in which North Carolina is located and that the units are retiring in 2016, the DAQ assumes that the model is not shifting coal generation from TVA units to EGUs located in North Carolina in 2018. However, the DAQ requests that the EPA confirm this. If the EPA finds that IPM is shifting coal capacity from retired TVA units to North Carolina EGUs, the DAQ has concerns with this because the TVA facilities are shutting down as part of a consent decree due to a lawsuit brought by North Carolina which stated that emissions from coal-fired power plants owned and operated by TVA were resulting in substantial amounts of NOx emissions and ozone being transported into North Carolina and preventing North Carolina from achieving attainment and maintenance of the ozone NAAQS. (See http://www.ncdoj.gov/getdoc/bdf66401-8137-4be2-bd20-57e89b570c1a/TVA-signed-consent-decree.aspx).

Table 8. TVA Retirements from the EPA Incremental Change Excel File

Commenter/Affiliation	Unique ID	Plant Name	Unit Number	State	Data Field of Interest	Value in NEEDS	Suggested Value*	Documentation and Comments
TVA / John W. Myers	47_B_1	Colbert	1	AL	Retire	9999		All 5 units will be retired per EPA Consent Agreement
TVA / John W. Myers	47_B_2	Colbert	2	AL	Retire	9999		
TVA / John W. Myers	47_B_3	Colbert	3	AL	Retire	9999		
TVA / John W. Myers	47_B_4	Colbert	4	AL	Retire	9999		
TVA / John W. Myers	1378_B_1	Paradise	1	KY	Retire	9999		TVA has announced plans to retire unit 1 and 2.
TVA / John W. Myers	1378_B_2	Paradise	2	KY	Retire	9999		
TVA / John W. Myers	50_B_8	Widows Creek	8	AL	Retire	9999		TVA has announced plans to retire unit 8.

*TVA did not provide a suggested value

2. Heat Rate for Roxboro Units 1, 2, 3A, 3B, 4A, and 4b

The EPA's excel spreadsheet called "Incremental_Updates_to_NEEDS.xlsx" indicates that a utility commenter, Capital Power, suggested revising the heat rate for the "Roxboro" plant because these units were stated by the commentator to "*generate RECs through the combustion of wood and TDF the values should be adjusted upwards*". This information refers to a 46 MW power plant located in Roxboro, NC and owned by Capital Power, Inc. called **CPI USA NC Roxboro** in the NEEDS input file with ORIS ID 10379. However, as shown in Table 9 below, the NEEDS 5.14 input file indicates that heat rates were revised for two facilities, both CPI USA NC Roxboro (ORIS ID 2712) and Duke Energy Roxboro (ORIS ID 2712).

Table 9. NEEDS v5.14 Input File Presenting Incorrect Heat Rates for Duke Energy Roxboro

Unique ID	State Code	County Name	County Code	ORIS Code	Unit ID	Plant Name	Heat Rate	On-Line Year	Plant Type
10379_B_1A	37	Person	145	10379	1A	CPI USA NC Roxboro	14900	1987	Biomass
10379_B_1B	37	Person	145	10379	1B	CPI USA NC Roxboro	14900	1987	Biomass
10379_B_1C	37	Person	145	10379	1C	CPI USA NC Roxboro	14900	1987	Biomass
2712_B_1	37	Person	145	2712	1	Roxboro	14900	1966	Coal Steam
2712_B_2	37	Person	145	2712	2	Roxboro	14900	1968	Coal Steam
2712_B_3A	37	Person	145	2712	3A	Roxboro	14900	1973	Coal Steam
2712_B_3B	37	Person	145	2712	3B	Roxboro	14900	1973	Coal Steam
2712_B_4A	37	Person	145	2712	4A	Roxboro	14900	1980	Coal Steam
2712_B_4B	37	Person	145	2712	4B	Roxboro	14900	1980	Coal Steam

The heat rate specified by the commenter (14,900 Btu/kWh) does not apply to the Roxboro plant owned and operated by Duke Energy. In addition, the DAQ has confirmed the units owned and operated by Duke Energy are permitted to burn only coal and fuel oil. The DAQ requests that the EPA correct the heat rates at the Duke Energy Roxboro units to the values shown in Table 10.

Table 10. NC DAQ Recommended Heat Rates for Duke Energy Roxboro Units for NEEDS v5.14

Unique ID	State Code	County Name	County Code	ORIS Code	Unit ID	Plant Name	Recommended Heat Rate (Btu/kWh)	Reference for Heat Rate
2712_B_1	37	Person	145	2712	1	Roxboro	8,871	AMPD 2012
2712_B_2	37	Person	145	2712	2	Roxboro	8,581	AMPD 2012
2712_B_3A	37	Person	145	2712	3A	Roxboro	9,583	Duke Energy
2712_B_3B	37	Person	145	2712	3B	Roxboro	9,475	Duke Energy
2712_B_4A	37	Person	145	2712	4A	Roxboro	9,971	Duke Energy
2712_B_4B	37	Person	145	2712	4B	Roxboro	10,027	Duke Energy

3. Revised NOx Emissions Factors and Retrofit of NOx Controls at GG Allen

There are several changes to the assumptions in the NEEDS 5.14 input file which are driving IPM forecast regarding Unit 3 and Unit 4 at the GG Allen facility. The changes result in a 300% difference in NOx emissions between EPA's forecast and Duke Energy's forecast. The DAQ presents its analysis of EPA's revised assumptions and its impact on the forecast in the following paragraphs and tables. Note the DAQ is not clear on how EPA's revisions were actually implemented in the input file and/or model. Regardless of the implementation, the DAQ does not believe the resulting forecast is realistic for Unit 3 and Unit 4. The DAQ requests that the EPA address how the assumptions were implemented and correct the forecast to reflect a more realistic outcome.

a. The EPA examined NOx emission rates for select units across the U.S. that were calculated from AMPD for years 2011 and 2014 (See Incremental Changes Document for NEEDS v5.14 on page 8). The EPA found that there was a significant increase, greater than 45%, in the NOx rate for GG Allen Units 3 and 4 from 2011 to 2014. The EPA concluded that selective non-catalytic reduction (SNCR) controls installed on Unit 3 and Unit 4 were turned off at these units in 2014, and changed the 2011 AMPD average annual NOx rate to the 2014 AMPD average annual NOx rate. The table from the Incremental Change document is given below in Table 11 along with the actual NOx rates from the AMPD.

Table 11. EPA Revised NOx Rates (lb/MMBtu) for North Carolina in NEEDS v5.14

Facility	Unit	Control	2014 Assumption	M1	M2	M3	M4	NEEDS 5.13 2018	NEEDS 5.14 2018	AMPD 2011	AMPD 2014
Belews Creek	2	SCR	On	**0.1**	0.1	0.1	0.1	0.05	0.10	0.06	0.11
G G Allen	3	SNCR	Off	0.36	0.21	0.36	0.21	Retired	0.36	0.22	0.37
G G Allen	4	SNCR	Off	0.36	0.21	0.36	0.21	Retired	0.35	0.22	0.36
Marshall	3	SCR	On	**0.14**	0.14	0.14	0.14	0.04	0.14	0.04	0.14
Mayo	1A	SCR	On	**0.15**	0.15	0.15	0.15	0.08	0.15	0.08	0.16
Mayo	1B	SCR	On	**0.15**	0.15	0.15	0.15	0.08	0.15	0.08	0.16
Roxboro	2	SCR	On	**0.15**	0.15	0.15	0.15	0.08	0.15	0.08	0.15

The DAQ believes that the EPA incorrectly assumes that the SNCR NOx controls at GG Allen Unit 3 and Unit 4 were turned off for two reasons. First, the uncontrolled rate for these units is approximately 0.44 lb/MMBtu based on the 2000 AMPD annual data representing pre-SNCR NOx rates. If SNCR was turned off on these units, the NOx emission rate would have been higher than 0.36 lb/MMBtu. Second, these units no longer function as base load units as they did in 2011. During calendar year 2014, the units were operated as “intermediate units” per the Duke Energy 2013 Integrated Resource Plan (IRP). Table 12 presents the decrease in the annual capacity factor for the coal-fired units at GG Allen from 2011 to 2014.

Table 12. Annual Capacity Factors for Coal Units at GG Allen from 2011 to 2014

Facility Name	Unit ID	2011	2012	2013	2014
G G Allen	1	26%	6%	4%	16%
G G Allen	2	19%	5%	2%	13%
G G Allen	**3**	**36%**	**21%**	**21%**	**20%**
G G Allen	**4**	**34%**	**21%**	**24%**	**18%**
G G Allen	5	31%	12%	13%	20%

Note there was a slight increase in utilization for Unit 1, Unit 2 and Unit 5 during 2014 from 2013. This was due to the use of the units during an extreme cold event in January of 2014. Ozone season operation of all the units continued to be very low both in the number of hours operated and percent load. This is documented in Table 13 by the low operating hours and the low calculated utilization factors for all the units at GG Allen during the 2014 ozone season. The Average Ozone Season Daily Utilization Factor for the days the units operated is also given to present the average operating load of each unit.

Table 13. 2014 Ozone Season AMPD Operating Hours and Utilization for Units at GG Allen

Unit	Operating Time	Percent of Ozone Season Operating Hours	Heat Input (MMBtu)	Max Capacity Input MMBtu/hr	Average Ozone Season Utilization Factor	Average Ozone Season Daily Utilization Factor
1	1,646	4%	1,793,967	2,141	2%	47%
2	1,334	3%	1,461,087	2,408	1%	42%
3	**1,712**	**4%**	**2,693,170**	**3,316**	**2%**	**39%**
4	**1,426**	**3%**	**2,381,114**	**4,151**	**1%**	**35%**
5	1,695	4%	2,911,676	3,997	2%	37%

The DAQ believes the increased NOx rate in 2014 is due to low load operation because SNCR is much less effective at operating loads below 50%. This is due to the narrow temperature range required for the SNCR reaction to occur. Therefore, it is more likely that the low operating load has caused the increase in the NOx rate rather than shutting off SNCR. Furthermore, under North Carolina Session Law 2002-4, Duke Energy is allowed to recover the cost of the reagent. Therefore, for this reason, there is no economic incentive for Duke Energy to purchase allowances to offset any emissions increases associated with discontinue operation of SNCR on these units at any time during the year.

http://www.epa.gov/ttncatc1/dir1/fsncr.pdf
http://www.ncga.state.nc.us/Sessions/2001/Bills/Senate/PDF/S1078v5.pdf

b. The IPM-NEEDS 5.14 output file indicates that Allen Unit 3 and Unit 4 are retrofit by the model with selective catalytic reaction (SCR) NOx controls. It then retires the remaining units at GG Allen and several units at Marshall. Table 14 presents the data from the IPM output file for NEEDS 5.14 base case.

Table 14. Data from IPM Base Case 2018 Output File for NEEDS v 5.14

Plant Name	Unit ID	Retirement Year	Plant Type	RetrofitSO2NOxControls
G G Allen	3	9999	Coal Steam	SCR
G G Allen	4	9999	Coal Steam	SCR
G G Allen	1	9999	Coal Steam	Coal Retirement
G G Allen	2	9999	Coal Steam	Coal Retirement
G G Allen	5	9999	Coal Steam	Coal Retirement
Marshall	1	9999	Coal Steam	Coal Retirement
Marshall	2	9999	Coal Steam	Coal Retirement
Marshall	3	9999	Coal Steam	
Marshall	4	9999	Coal Steam	Mercury Control

Retrofitting GG Allen Unit 3 and 4 with SCR causes the model to significantly increase fuel use and coal generation at those units in 2018 from 2013 levels. (The DAQ does not use 2014 for this comparison due to the increased use of Allen during the natural gas curtailment). Table 15 presents the fuel use and generation forecast in 2018 using the new IPM-NEEDs v5.14 and the AMPD 2013 data, and the 2018 fuel use forecast that Duke Energy submitted to the DAQ on May 19, 2015. The IPM forecasted total coal use for GG Allen to increase by 70% (from 20.1 trillion British thermal units (TBtu) in 2014 to 34.3 TBtu in 2018). However, Duke Energy has forecasted total coal use in 2018 to decrease by about 50% relative to 2013 levels. Note that in the previously published base case (IPM-NEEDS v5.13), all the units at GG Allen were retired by 2018.

Table 15. Comparison of GG Allen Data- IPM-NEEDS v5.14 Forecast for 2018, 2014 AMPD Actual Values, and Duke Energy Forecast for 2018

GG Allen	2018 Forecast IPM-NEEDS v5.14			AMPD 2013			2018 Forecast Duke Energy Forecast		
Unit ID	Generation GWh	Fuel Use Tbtu	NOx Emissions tons	Generation GWh	Fuel Use Tbtu	NOx Emissions tons	Generation GWh*	Fuel Use Tbtu	NOx Emissions tons
1	0	0.0	0.0	72	0.7	87	N/A	1.0	142
2	0	0.0	0.0	44	0.4	57		0.4	53
3	1,879	16.7	3,020	686	6.0	1001		2.4	351
4	*1,987*	*17.6*	*3,100*	*993*	*8.6*	*1422*		*3.6*	*527*
5	*0*	*0.0*	*0.0*	*472*	*4.5*	*589*		*2.2*	*330*
Total	***3,865***	***34.3***	***6,120***	***2,267***	***20.1***	***3,155***	***N/A***	***9.5***	***1,403***

*Duke Energy did not provide generation data

The DAQ questions the model's forecast of an SCR retrofit on GG Allen Unit 3 and Unit 4 since these units have SNCR installed already. It is unlikely that Duke Energy would retrofit these two units with SCR given the limited footprint at the plant, the capital cost of the retrofit and Duke's low coal utilization forecast for the plant. In addition, Duke Energy has built substantial amounts of NGCC units which it now operates as base load (See previous Section 1.c). We believe another approach should be considered such as only modifying the NOx emission rate while maintaining SNCR as "on" in order to correct the 2018 forecast to match the forecast provided by Duke Energy.

c. The IPM then applies the EPA Revised NOx emissions rates for GG Allen Unit 3 and Unit 4 (0.36 lb/MMBtu) given in Table 11 to the increased heat input in model year 2018. This results in high NOx emissions from those units in 2018 as shown in Table 15. The DAQ believes this is an error in the model. If the model is assuming the Allen Unit 3 and Unit 4 get an SCR and heat input increases substantially, the NOx rates should not remain at 0.36 lb/MMBtu for future years. The NOx rate should be lowered to rates expected with an SCR, which are generally below 0.1 lb/MMBtu.

d. There has been no indication from Duke Energy that the units at the Marshall facility will be shut down. These units are currently operating at high utilization factors and the Duke Energy forecast for 2018 indicates the future utilization to be similar to that in 2014.

   Table 16 presents the annual utilization factor for the units at the Marshall and GG Allen facilities for year 2014 using EPA's AMPD. In addition, the table presents Duke Energy's latest forecast for utilization of the units at Marshall and GG Allen for year 2018. The data indicates that GG Allen will continue to be utilized at low rates, less than 10%, while the units at Marshall will be used at utilization rates between 24% and 62%.

Table 16. 2014 EPA AMPD Annual Capacity Factors for Marshall and GG Allen

			2014 AMPD Data		Duke Energy 2018 Forecast	
Facility	Unit	Capacity Heat Input Rate (MMBtu/hr)	2014 Heat Input (MMBtu)	Annual Capacity Factor	2018 Heat Input MMBtu	Annual Capacity Factor
Marshall	1	4,756	18,077,426	43%	10,206,978	24%
Marshall	2	4,542	20,200,660	51%	14,640,160	37%
Marshall	3	7,506	41,843,811	64%	35,425,588	54%
Marshall	4	7,486	12,393,300	19%	40,800,022	62%
GG Allen	1	2,141	2,939,523	16%	988,239	5%
GG Allen	2	2,408	2,676,135	13%	360,688	2%
GG Allen	**3**	**3,316**	**5,801,119**	**20%**	**2,369,681**	**8%**
GG Allen	**4**	**4,151**	**6,369,752**	**18%**	**3,551,946**	**10%**
GG Allen	5	3,997	6,863,051	20%	2,218,379	6%

Given the 2014 AMPD and the Duke Energy 2018 forecast presented above, the DAQ believes that it is plausible that GG Allen Unit 3 and Unit 4 would be retired rather than retrofitted with SCR, especially given the low capacity factors at which these units are currently operating and that the Duke Energy forecast shows zero heat input and emissions for all five units in 2030. Currently, Duke operates Units 1 through 5 at GG Allen and Units 1 and 2 at Marshall as "intermediate" units rather than as base load units, according to the Duke Energy 2013 IRP.

4. HF Lee NGCC Start Date

In the Incremental Change notes, the EPA states:

> Finding: under construction in 2012; Notes1: agree w CPP comment - if any generation was created at EOY 2012 it was commissioning / start-up
>
> Action: Revise data accordingly

However, it appears in the NEEDS 5.14 database that the start date is still **2012** instead of the corrected date, January 1, 2013. This will potentially impact the proposed Clean Power Plan Goal calculations and any associated policy analysis conducted by the EPA. The DAQ asks that the EPA revise the start date to January 1, 2013.

5. Rosemary and Butler-Warner NGCC units

Units at the Rosemary and Butler-Warner facilities units are shown in the NEEDs v5.14 input file as NGCC. While some of these units are NGCC units, they function as peaking units. The DAQ addressed these units in its 111d comments.

This issue was not discussed in the EPA's Incremental Change documentation. The DAQ requests clarification as to whether the EPA accepted this comment or not and to state whether these units are considered peaking units or not for rule making purposes.

6. L. V. Sutton NGCC

In the Incremental Change notes, EPA states:

> Finding: Research Finding: Nov 2013; Notes1: SNL data; Notes2: Start year = 2013; (See e-mail/attachment for details) Per 2013 EIA Form 860
>
> Action: No revision

NC DAQ would like to review the e-mail and attachments which discuss the start date for LV Sutton.