Developing Southern Company Emissions and Flue Gas Characteristics for VISTAS Regional Haze Modeling

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ABSTRACT

Developing the emissions inventory is an important step towards using regional scale atmospheric models in regulatory air quality management. The ability of atmospheric models to simulate observed air quality depends heavily on accurate spatial and temporal representation of emission source sectors such as point, area, non-road, on-road and biogenic. Confidence in the atmospheric model's ability to simulate future air quality and its response to an emission control strategy depends on methodologies used to project emission source sectors and understanding of associated uncertainties. Electric generating units (EGU's) constitute an important component of the point source sector and are often subjected to emission control considerations. Therefore, it is especially important to accurately represent EGU emissions and its flue gas characteristics in any regulatory modeling application.

This paper summarizes the methodology used to create unit level, hourly emissions and flue gas characteristics for Southern Company EGU's for use by Visibility Improvement State and Tribal Association of Southeast (VISTAS).[1] Emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC's) and total filterable particulate matter (PM-FIL) were developed for the VISTAS scenarios: base year 2002, typical year 2002, and future years 2009 and 2018. Hour specific flue gas characteristics (flow rate and temperature) were also calculated for the VISTAS scenarios.

INTRODUCTION

Background

VISTAS is the Regional Planning Organization (RPO) for the southeastern United States, established to coordinate activities associated with the management of regional haze and visibility. VISTAS is comprised of southeastern states, tribal governments and various federal agencies with participation from industry stakeholders. As part of its objectives, VISTAS is developing a common set of emissions inventories for use by southeastern states and tribes in the regional haze regulatory process. Community Multiscale Air Quality (CMAQ) model ready emissions files for base year 2002, typical year 2002, and future years 2009 and 2018 are being developed with input from participating states and stakeholders using the Sparse Matrix Operator Kernel Emissions (SMOKE) emissions model.

Southern Company is a super-regional energy company with 4 million customers and 39,000 megawatts of generation capacity in the southeast. Southern Company owns EGU's in Alabama, Florida, Georgia and Mississippi and participates in VISTAS as an industry stakeholder. Using an in-house methodology, Southern Company created emissions and flue gas characteristics for its EGU's for potential use in VISTAS emission inventory development. It should be noted that VISTAS is using Southern Company developed emissions and flue gas characteristics only for the following scenarios.

- Base year 2002, not including Southern Company units located in Georgia with Continuous Emissions Monitoring System (CEMS).
- Typical year 2002
- Future year 2009 and 2018 for Southern Company EGU's located in Mississippi.

Other methods were used by VISTAS to develop Southern Company (when Southern Company supplied data was not used) and other EGU emissions and flue gas characteristics, descriptions of which are beyond the scope of this paper. Readers are directed to VISTAS web site for additional information.[2]

Purpose

This paper explains the methodology used by Southern Company to create unit level, hourly emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC's) and total filterable particulate matter (PM-FIL) for the VISTAS scenarios: base year 2002, typical year 2002, and future years 2009 and 2018. The future year emissions inventories were developed for business-as-usual or "On The Books" (OTB) case and anticipated controls to be in compliance with Clean Air Interstate Rule (CAIR) or CAIR case. The methodology used to create hour specific flue gas flow rate and temperature for the VISTAS scenarios will also be discussed.

METHODOLOGY

Base year 2002

The steps followed to develop Southern Company EGU emissions inventory and flue gas characteristics for base year 2002 in National emissions inventory Input Format (NIF) version 3.0 [3], are described in this section. Emissions and flue gas characteristics were developed for all fossil-fueled units owned and centrally dispatched by Southern Company, including units without CEMS. Hourly SO_2 and NO_X data could be directly obtained from CEMS for units having such devices, but we chose the traditional "emissions factor" approach for the following reasons.

- CO, VOC, and PM-FIL are not measured by CEMS and will have to be calculated.
- CEMS contain "filled" data to meet specific CEMS QA/QC requirements that may not be realistic for atmospheric modeling application.
- Emissions factor approach provides consistency across all Southern Company units with and without CEMS.

Step 1: Calculate Actual Heat Input from Generation Data for Base Year 2002

Historical net generation records of Southern Company EGU's are maintained in the Energy Management Systems (EMS) database. The EMS database was queried to obtain hourly net generation for every Southern Company fossil-fueled EGU for VISTAS base year 2002. The net generation was used in the net heat rate equation to generate hourly actual heat input for each EGU as shown below.

Equation (1) $HI_{i,j} = a_j + b_j * NetGen_{i,j} + c_j * [NetGen_{i,j}]^2$

Where

$HI_{i,j}$ = Actual Heat Input, in Million Btu's (mmBTU) for each hour "i" and EGU "j"

$NetGen_{i,j}$ = Net generation in Mega Watt-Hr (MWh) for each hour "i" and EGU "j"

a_j, b_j, and c_j = Heat rate coefficients for EGU "j"

The heat rate coefficients are unit specific and were obtained from operational data and plant tests.

Step 2: Calculate SO_2, NO_X, CO, VOC and PM-FIL emissions for Base Year 2002

In this step, heat input for each EGU, on an hourly basis obtained from Step 1, was multiplied with SO_2, NO_X, CO, VOC and PM-FIL emission rates for that unit to get hourly SO_2, NOx, CO, VOC and PM-FIL emissions.

Equation (2) $SO_2\ Emis_{i,j} = SO_2\ rate_j * HI_{i,j}$

Equation (3) $NOx\ Emis_{i,j} = NO_X\ rate_j * HI_{i,j}$

Equation (4) $CO\ Emis_{i,j} = CO\ rate_j * HI_{i,j}$

Equation (5) $VOC\ Emis_{i,j} = VOC\ rate_j * HI_{i,j}$

Equation (6) $PM\text{-}FIL\ Emis_{i,j} = PM\text{-}FIL\ rate_j * HI_{i,j}$

Where

“SO_2 , NOx, CO, VOC, PM-FIL ” $Emis_{i,j}$ = SO_2 , NO_X, CO, VOC, PM-FIL emissions in pounds for each hour “i” and EGU “j”

“SO_2 , NOx, CO, VOC, PM-FIL ” $rate_j$ = SO_2 , NO_X, CO, VOC, PM-FIL emission rate in pounds per million Btu (lb/MMBTU) for each EGU “j”

CO and VOC emission rates were obtained from either AP-42 factor handbook (Air CHIEF 11.0) [4] or vendor specifications. SO_2 and NO_X rates were obtained from 2002 CEMS for EGU’s with CEMS and from Title V permit limits for units without CEMS. NOx and SO_2 rates from CEMS were averaged monthly for each EGU and applied uniformly for every hour of the month. PM-FIL rates were obtained mostly from stack test data. For units without stack test data, PM-FIL rates were obtained from AP-42 factor handbook. The emissions rates were checked for reasonableness by an engineer expert on these matters. Any rates deemed unreasonable were investigated and resolved.

Step 3: Calculate Flue Gas Flow Rate and Temperature for Base Year 2002

In this step, hourly EGU specific flue gas flow rate and temperature were calculated based on hourly generation. Since the EMS database provides only net generation (generation dispatched to the grid), it has to be converted to gross generation (total generation from the EGU including service load) first before flow rate and temperature can be calculated. The gross generation was calculated from net generation using the following empirical equations.

Equation (7) $t1 = B_j * NetGen_{i,j}$

Equation (8) $t2 = A_j + t1$

Equation (9) $t3 = t2 - C_j$

Equation (10) $GrossGen_{i,j} = t3/D_j$

Where

$NetGen_{i,j}$ = Net generation in MWh for each hour “i” and EGU “j”

GrossGeni,j = Gross generation in MWh for each hour “i” and EGU “j”

A_j, B_j, C_j, D_j = Generation coefficients for EGU “j”

The generation coefficients are unit specific and are based on plant efficiency, service load, and fuel used. Hourly flue gas flow rate and temperature for each EGU were then calculated as follows.

If $GrossGen_{i,j}$ < 50 % of the maximum generation capacity of the EGU then,

Equation (11) $Flow_{i,j}$ = Flow rate at 50% EGU capacity

Equation (12) $Temperature_{i,j}$ = Temperature at 50% EGU capacity

If $GrossGen_{i,j}$ > 50 % of the maximum generation capacity of the EGU then,

Equation (13) $Flow_{i,j}$ = Linearly interpolated flow rate between 50% and 100% EGU capacity

Equation (14) $Temperature_{i,j}$ = Linearly interpolated temperature between 50% and 100% EGU capacity

Where

$Flow_{i,j}$ = Flue gas flow rate in Acutal Cubic Feet (ACF) for hour “i” and EGU “j”

$Temperature_{i,j}$ = Temperature in Degree Fahrenheit (Deg F) for hour “i” and EGU “j”

Flue gas flow rates and temperatures at 50% and 100% EGU capacity are unit specific and were obtained from equipment manufacturer specifications.

Steps 1 thru 3 were performed using perl scripts that calculates emissions and flue gas characteristics, merges them with plant identifiers and outputs the results in NIF version 3.0 format.

Typical Year 2002

The steps followed to develop Southern Company EGU emissions inventory and flue gas characteristics for typical year 2002 in NIF version 3.0 format, are described in this section. Typical year 2002 emissions and flue gas characteristics were developed for all fossil-fueled units owned and centrally dispatched by Southern Company, including units without CEMS. VISTAS is developing typical year 2002 emissions for the following reasons.

- To represent the five year (2000-2004) starting period that would be used to determine the regional haze "reasonable progress goals" for 20% worst and 20% best visibility days.
- To avoid anomalies in emissions source sectors due meteorology, economic, and outage factors in 2002, which could skew the requirement to assess CMAQ modeling results in a "relative sense" for regional haze regulatory purposes.

Step 1: Create Generation and Heat Input Data for Typical Year 2002

The Generation Services department routinely develops energy budget forecasts for Southern Company using PROSYM, a Chronological Production Modeling System.[5] Inputs to PROSYM model include load forecasts, EGU characteristics, off-system sale, and fuel costs. PROSYM can provide operational information for each existing and planned "generic" EGU based on projected energy demand, plant efficiency, fuel cost, enforced outage (EFOR), planned outage (PO) and retirements. PROSYM provides for every EGU, net generation and heat input forecast for a typical week, for every month, for twenty years into the future. The 2002 version of the energy budget forecast was used to create net generation and heat input for every Southern Company EGU for the year 2002. Typical week forecasts were duplicated to populate each day of the month. Use of PROSYM forecasts in typical year 2002 emissions inventory development is appropriate because it provides information about how Southern Company expected to operate its EGU's under "typical" economic and meteorological conditions. EFOR's and PO's forecasted by PROSYM were kept in typical year 2002 emissions inventory development because it is part of an EGU's "typical" operation and it would be unrealistic force "no outages" for an entire year in the PROSYM model.

Step 2: Calculate SO_2, NO_X, CO, VOC and PM-FIL emissions for Typical Year 2002

In this step, heat input for each EGU, on an hourly basis obtained from Step 1, was multiplied with SO_2, NO_X, CO, VOC and PM-FIL emission rates for that unit to get hourly SO_2, NOx, CO, VOC and PM-FIL emissions. Equations 2 thru 6 were used with actual heat inputs substituted by forecasted heat inputs from the PROSYM model. SO_2, NO_X, CO, VOC and PM-FIL emissions rates used were EGU specific and identical to base year 2002 rates.

Step 3: Calculate Flue Gas Flow Rate and Temperature for Typical Year 2002

In this step, hourly EGU specific flue gas flow rate and temperature were calculated based on hourly forecasted generation. Since PROSYM model provides only net generation (generation dispatched to the grid), it has to be converted to gross generation (total generation from the EGU including service load) first before flow rate and temperature can be calculated. The gross generation was calculated from net generation using the empirical equations 7 thru 10, with $NetGen_{i,j}$ obtained from the PROSYM model for hour "i" and EGU "j". Hourly flue gas flow rate and temperature for each EGU were then calculated by using equations 11 and 12 for forecasted $GrossGen_{i,j} < 50\%$ of EGU capacity and equations 13 and 14 for forecasted $GrossGen_{i,j} > 50\%$ of EGU capacity.

Steps 1 thru 3 were performed using perl scripts that calculates emissions and flue gas characteristics, merges them with plant identifiers and outputs the results in NIF version 3.0 format.

Future Year 2009 and 2018

The steps followed to develop Southern Company EGU emissions inventory and flue gas characteristics for future years 2009 and 2018 in NIF version 3.0 format, are described in this section. Future year 2009 and 2018 emissions and flue gas characteristics were developed for all fossil-fueled units owned and centrally dispatched by Southern Company, including units without CEMS. In addition new “generic” units forecasted by PROSYM, needed in order to meet energy demand in 2009 and 2018 were also included. The future year emissions inventories were developed for the business-as-usual or “On The Books” (OTB) case and for anticipated controls to be in compliance with Clean Air Interstate Rule (CAIR) or CAIR case.

Step 1: Create Generation and Heat Input Data for Future Years 2009 and 2018

The 2004 version of the energy budget forecast was used to get net generation and heat input for every existing and future “generic” Southern Company EGU for the year 2009 and 2018. Monthly “typical week” forecasts from PROSYM were duplicated to populate each day of the month for 2009 and 2018. In order to avoid anomalies in EGU operation between typical year 2002 and the future years, 2002 typical EFOR’s and PO’s were forced into the PROSYM model when it dispatched units for 2009 and 2018.

Step 2: Calculate SO_2, NO_X, CO, VOC and PM-FIL emissions for Future Years 2009 and 2018

In this step, heat input for existing and future Southern Company EGU’s, on an hourly basis obtained from Step 1, was multiplied with SO_2, NO_X, CO, VOC and PM-FIL emission rates for that unit to get hourly SO_2, NOx, CO, VOC and PM-FIL emissions. Equations 2 thru 6 were used with actual heat inputs substituted by forecasted heat inputs from PROSYM model for 2009 and 2018 separately. SO_2, NO_X, CO, VOC and PM-FIL emissions rates used were EGU specific and were different for 2009, 2018 OTB and CAIR cases. The emission rates were obtained from internal Southern Company compliance strategy (2003 version) under OTB and CAIR cases for 2009 and 2018. Emission rates for future “generic” units were calculated from either existing similar units or from latest equipment vendor specifications. Seasonal and year around controls were considered and emission rates were changed accordingly.

Step 3: Calculate Flue Gas Flow Rate and Temperature for Future Years 2009 and 2018

In this step, hourly EGU specific flue gas flow rate and temperature were calculated based on hourly forecasted generation for 2009 and 2018. Since the PROSYM model provides only net generation (generation dispatched to the grid), it has to be converted to gross generation (total generation from the EGU including service load) first before flow rate and temperature can be calculated. The gross generation was calculated from net generation using the empirical equations 7 thru 10, with $NetGen_{i,j}$ obtained from PROSYM model for hour “i” and EGU “j” for 2009 and 2018. Hourly flue gas flow rate and temperature for each EGU were then calculated by using equations 11 and 12 for forecasted $GrossGen_{i,j}$ < 50% of EGU capacity and equations 13 and 14 for forecasted $GrossGen_{i,j}$ > 50% of EGU capacity. Flue gas flow rates and temperatures at 50% and 100% EGU capacity for future “generic” units were obtained from latest equipment manufacturer specifications.

Locations of future “generic” units were based on proximity to load centers and availability of transmission and gas supply infrastructure. The location and stack parameters of future “generic” units were included in the files submitted to VISTAS and were given explicit identifiers.

Steps 1 thru 3 were performed using perl scripts that calculates emissions and flue gas characteristics, merges them with plant identifiers and outputs the results in NIF version 3.0 format.

CONCLUSIONS

This paper summarizes the methodology used by Southern Company to develop hourly, SO_2, NO_X, CO, VOC, and PM-FIL emissions and flue gas characteristics for its EGU's for the VISTAS scenarios: base year 2002, typical year 2002, and future years 2009 and 2018. The Southern Company methodology incorporates EGU specific information such as plant efficiency, operational data, stack tests, heat rate curves, generation cost and future generation forecast to provide more realistic emission estimates for base year, typical year and future years. The Southern Company methodology offers an alternative to other EGU emission development techniques and is more suited for regulatory modeling applications for the following reasons.

- EGU specific information is incorporated avoiding the use of generic profiles or plant data.
- Hourly emissions of SO_2, NO_X, CO, VOC, and PM-FIL along with flue gas temperature and flow were developed in a consistent manner for base year 2002, typical year 2002, and future years 2009 and 2018. Such consistency in emission development methodology is highly desired when air quality modeling results are used in a relative sense.
- Southern Company is in the business of supplying electricity to its 4 million, plus growing, customers in the most reliable and economical way. In order to do that Southern Company gathers plant operational data, conducts stacks tests, and uses sophisticated energy forecast models, all of which can add value in any emissions and air quality modeling application.

REFERENCES

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KEYWORD

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