ERTAC EGU Tool: Origin and Uses

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ABSTRACT

Emission estimates from electrical generating units (EGUs) are critical to the development of state implementation plans (SIPs) and air quality modeling exercises, both of which are required by the Clean Air Act (CAA) to improve air quality. The Eastern Regional Technical Advisory Committee (ERTAC) established a workgroup consisting of representatives from state agencies, planning organizations, and industry that worked together to develop a stable and transparent freeware emissions estimation tool designed specifically for these types of applications. The tool, called the ERTAC EGU tool, allows users to evaluate peak day and hourly activity and emissions as well as annual emissions inventories. Input files contain conservative assumptions about fuel changes, regional generation, growth rates, and plant operation. Actual hourly data supplied by EGU owners to the Clean Air Markets Division (CAMD) of the United States Environmental Protection Agency (EPA) form the basis for future year projections. Users may customize inputs to produce results that reflect state or regional concerns. This paper explains the need for such a tool in SIP and modeling efforts, the process by which the ERTAC workgroup developed the tool, how the tool operates, applications of the tool, post-processors developed for use with this tool, and future tool applications and upgrades.

INTRODUCTION

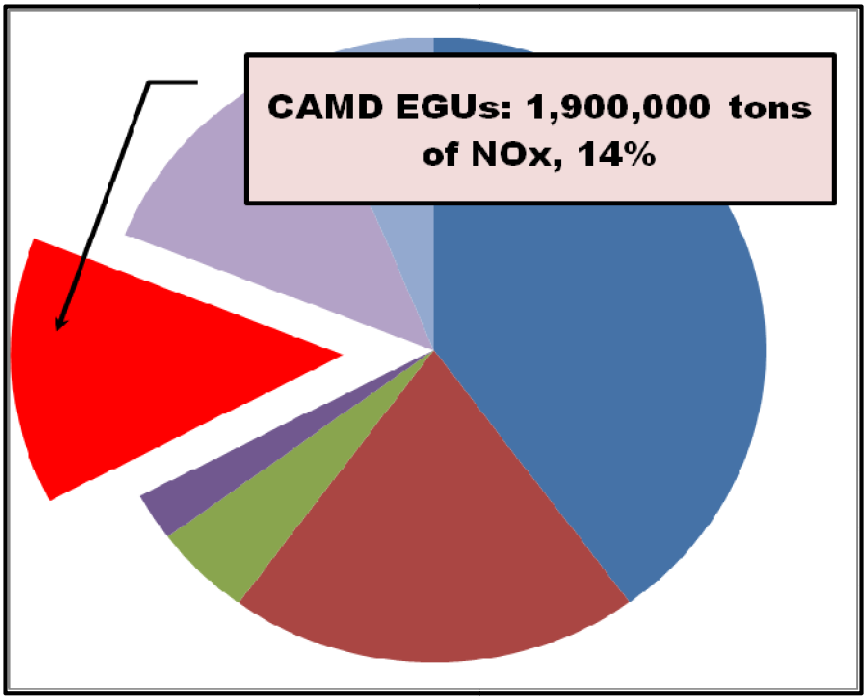
State air pollution control agencies require base year inventories to satisfy CAA requirements for areas not attaining federal national ambient air quality standards (NAAQS) and for developing SIPs to improve visibility in federally protected areas called Class I areas. These inventories represent actual, typical emissions during a particular year. Agencies responsible for air quality improvement and planning rely on these inventories as the basis for many environmental efforts. Most importantly, the base year emissions, coupled with base year meteorology and ambient air concentrations, are the foundation for future year air quality projections in years designated as compliance deadlines by EPA for various NAAQS and visibility efforts.

For example, EPA recommends 2011 as the base year for the 2008 ozone NAAQS. See 40 CFR 51.1110(b) (80 FR 12316).[1] States use the 2011 base year inventory in conjunction with 2011 ambient air quality and meteorology to project expected air quality in the year of the mandated compliance deadline. For moderate ozone nonattainment areas under the 2008 ozone NAAQS, the mandated compliance deadline is 2017.[2] These projections must account for the emissions benefits derived from the many federal and state emission control programs that are currently in place or will be implemented by 2017. These air quality projections determine if states must develop and implement further control programs to ensure healthy air quality by the compliance deadline.

Emissions from EGUs reporting to EPA's CAMD under 40 CFR Part 75 contribute a significant portion of the total anthropogenic inventory for two pollutants, nitrogen oxides (NO_X) and sulfur dioxide (SO_2). Figure 1 shows that this sector accounts for approximately 14% of all NO_X emissions in the 2011 National Emissions Inventory, version 1 (2011 NEIv1). Figure 2 shows that this sector accounts for approximately 71% of all SO_2 emissions within the 2011 NEIv1.[3]

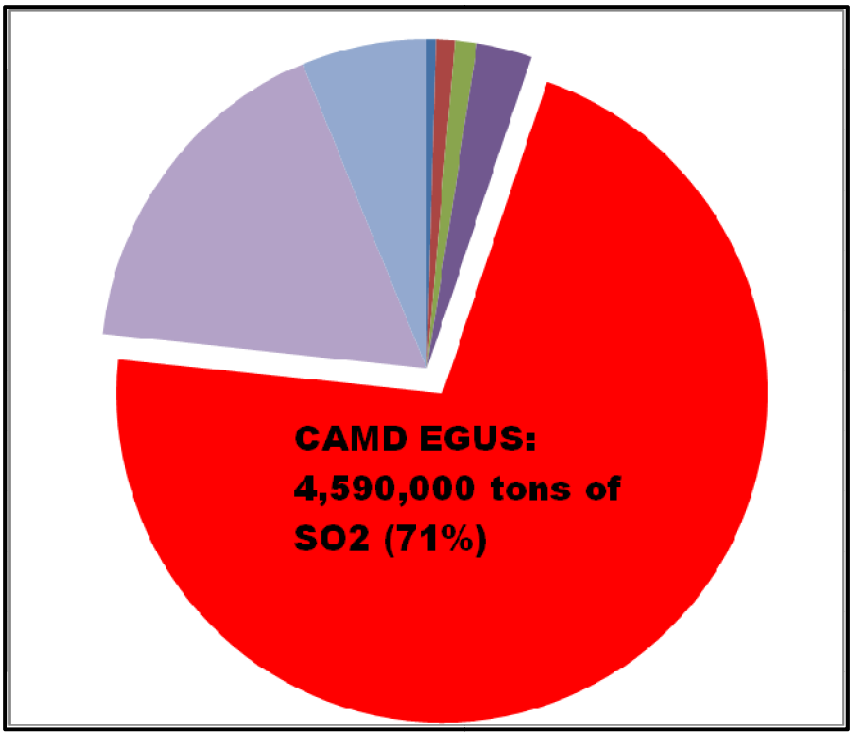
The CAMD data is especially useful for base and projection year emissions inventory development. As shown in Figures 1 and 2, the emissions from this sector represent a significant portion of the anthropogenic emissions. Unlike many other emissions categories, these emissions originate from discrete, stationary locations. In 2011, the EPA's on-line database at www.epa.gov/airmarkets/ shows that 4,810 units reported emissions data to CAMD. Other emissions inventory sectors represent far greater numbers of emitters. The relatively small CAMD source universe allows air quality modelers and inventory specialists to assign accurate latitude and longitude descriptions as well as representative stack flow, temperature, height, and velocity to each emitting unit.

Figure 1: 2011 NEIv1 NO_X emissions data.



In addition, the CAMD data is unique in its resolution. Units supply hourly data on activity and emissions.[4] Other sectors provide emissions or activity data used to estimate emissions at much broader resolutions. The hourly resolution of activity and emissions from the CAMD EGU sector relates well to meteorological data, which is also available at hourly resolutions. In air quality planning, this nexus between hourly emissions and hourly meteorological data is especially important. EPA guidance on the development of air quality assessments recommends that states assume future year meteorology that is identical to base year meteorology.[5]

Figure 2: 2011 NEI v1 SO_2 emissions data.



CAMD data is more rigorously quality-assured than data in other emissions sectors. Monitoring devices required by 40 CFR Part 75 meet stringent quality assurance and calibrations checks, which vary in frequency with unit utilization and emissions. Larger, more frequently used units must perform calibrations and other tests more often than smaller units.[6] Other types of industrial sources may be asked to certify their annual emissions data, and states perform routine quality reviews of such submitted data. However, the data are not generally reviewed at the hourly level. These characteristics of the hourly data in the CAMD database allow air quality models to accurately represent the impacts of these emissions units temporally and spatially.

The CAA requires that states pay special attention to large emitters in areas that do not comply with NAAQS, called nonattainment areas. States must include future year estimates of area emissions in clean air attainment plans.[7] Once an area demonstrates compliance with a NAAQS, states must project emissions from the area into a future year, generally at least ten to twelve years beyond the year in which the area achieves healthy air quality. These projections help ensure that the area maintains healthy air quality.[8] Due to the size of the emissions from some CAMD units, these units may be a disproportionally large segment of the emissions inventory in an area. For example, in the metropolitan Washington, D.C. 1997 fine particulate ($PM_{2.5}$) NAAQS 2002 base year inventory, SO_2 and NO_X from CAMD units were 88% and 26% of the annual emissions inventory, respectively.[9] The 1997 ozone NAAQS attainment plan for this same area shows that the CAMD EGUs contributed 19% of the 2009 NO_X emissions.[10] Predictions about future year emissions and activity at these units are therefore very important to attainment and maintenance planning for air quality standards.

ERTAC EGU TOOL DEVELOPMENT

For the reasons listed above, states identified the need for a tool that allows credible predictions of activity and emissions from the CAMD EGUs for use in air quality planning and modeling. ERTAC convened a workgroup to develop such a tool. ERTAC is a collaborative effort among states east of the Mississippi river and multi-jurisdictional organizations (MJOs) to improve emissions inventories. The

ERTAC committee identifies priority projects and recruits member organizations to volunteer time to work on these projects. ERTAC often invites industrial representatives to provide information and feedback on their areas of expertise. Past ERTAC projects include the development of a tool to calculate residential wood combustion emissions in collaboration with EPA, creation of a best practices document to estimate area source emissions, and development of a national rail inventory. More information on ERTAC may be found at www.ertac.us.

ERTAC EGU Workgroup

West Virginia, Wisconsin, and New Jersey representatives acted as the ERTAC EGU workgroup co-chairs. The workgroup consisted of four subgroups: implementation, growth, data tracking, and renewables and conservation programs. Southern, mid-Atlantic, and Midwestern states and MJO staff provided leadership and participated on each subgroup. Industry representatives also participated and provided valuable insight and feedback on the development efforts.

Each subgroup had specific tasks. The implementation subgroup developed the logic for the tool. The growth subgroup reviewed potential sources of growth projections to provide fuel-specific and technology-specific growth rates for short- and long-term projection windows. The growth subgroup also evaluated the use of peak and annual projection factors. The data tracking subgroup established a protocol for state and stakeholder outreach, data collection, and data management. The renewables and conservation program subgroup identified various renewable portfolios and their impacts on a variety of growth factors available for use within the program. The subgroup members also looked at ways future iterations of the tool could include benefits from conservation programs not already included in growth factors.

Workgroup Goals for the Tool

The workgroup identified a number of characteristics that the tool should possess to meet air quality planning needs. First, the tool should be readily accessible to organizations wishing to use it. The tool must be freeware and must run using readily available software programs. States responsible for air quality planning do not have resources to buy expensive software. Second, tool predictions must be conservative, containing no unexplained swings in activity or unexpected unit operational changes such as retirements, control installations, or fuel switches. Overly optimistic tool results could jeopardize the timely achievement of healthy air quality, which in turn may require the imposition of additional, costly regulations within an area. Also, air quality improvement and maintenance plans must undergo public review as part of the adoption process.[11] States must document changes to any major sector of the emissions inventory; therefore, important inputs to the ERTAC EGU tool must be transparent and available for review. Third, to facilitate air quality assessments for air quality improvement purposes and visibility improvement purposes, output files from the tool need to be at an hourly resolution and reflect the impact of the base and future year meteorology. Hourly resolution allows the evaluation of high electricity demand day (HEDD) impacts on air quality and visibility as well as the examination of other episodic effects, which are becoming very important to air quality planning as NAAQS standards become more stringent. Fourth, tool performance must allow for timely evaluations of new data as well as projection needs, both regionally and across the continental United States (CONUS). Due to compressed planning schedules as well as unforeseen situations such as the proposal of new rules or the need for maintenance plans, a flexible tool that allows states the ability to develop high quality projections for a variety of future years is very important to the planning process.

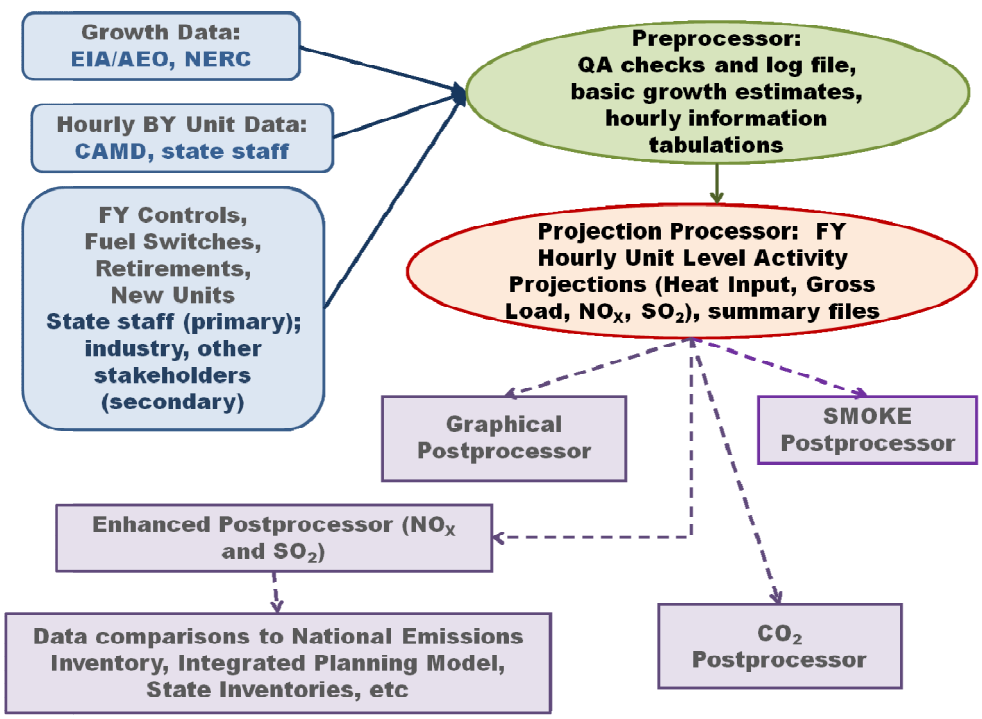
ERTAC EGU TOOL

The basis for future year projections within the ERTAC EGU tool is the CAMD hourly data from the base year. Base years may vary from standard to standard. For example, the recommended base year for the 1997 ozone NAAQS is 2002[12] while the recommended base year for the 2008 ozone NAAQS is 2011.[13] This base year hourly data, which reflects not only the meteorology of the base year but also the effects of fuel costs, commodity costs, and regional power demands in the base year, are coupled with unit-specific information provided by states and stakeholders. This unit-specific information provides parameters such as retirement dates, controls and emission rate changes, and size and efficiency specifications. State staff may adjust these parameters according to information they receive from sources such as permit applications, inventory statements, integrated resource plans (IRPs), and enforcement actions. This bottom-up approach allows the tool to create results that mesh well with the information available about future year activities within state archives.

Tool Structure

The tool uses a three-step approach to create future year projections, as shown in Figure 3. First, a preprocessor analyzes all input files used in the tool run. The preprocessor performs basic calculations needed for activity and emissions projections, but more importantly, it performs a series of quality assurance checks on the data in the input files. The preprocessor also provides a log file that notes each check performed and lists warnings and errors.

Figure 3: ERTAC EGU tool three step approach.



Generally, a warning is informational. If the warning is specific to a single unit and that unit does not have all necessary information, the unit will not process. However, the user may continue with the run using the input files. Errors are generally run-related information that may prevent the projection from completing. Information in the preprocessor log file is valuable for determining which units, regions, and fuel/unit types need extra scrutiny prior to running the projection processor.

After reviewing the preprocessing log and making necessary adjustments to input files, the user may need to rerun the preprocessor. Once the preprocessor output files are satisfactory, the next step is to run the projection processor. The projection processor calculates growth rates from a variety of data inputs and assigns future year generation and emissions to each unit on an hourly basis. The processor checks each unit's capacity and ensures that hourly activity does not exceed the unit's maximum calculated capacity. Required generation beyond a unit's capacity is reassigned to other available units. Where demand

exceeds the regional system capacity, the tool creates generation deficit units (GDUs). These GDUs ensure that the results reflect a scenario where available units, including new planned units (NPUs) supplied by states and GDUs, are able to meet all estimated future demand. The projection processor captures and reports hourly data in a file called the hourly diagnostic file, which is quite large. For a typical regional run, such as SRVC, this file is 280 megabytes. For a CONUS run, this file is four gigabytes. The projection processor also creates other output files that are useful for a variety of evaluations.

The third step is choosing and running one or more post-processors that match the user's needs. The enhanced post-processor provides unit-level summaries of emissions and activities for the base and future year as well as the respective ozone seasons. The enhanced post-processor is frequently used, especially for comparing ERTAC outputs to other databases. The ERTAC EGU workgroup is examining how the enhanced post-processor may be incorporated into the projection processor in a future tool upgrade. The ERTAC-to-SMOKE post-processor combines ERTAC EGU tool outputs with other data and creates files ready for input into the Sparse Matrix Operator Kernel Emissions (SMOKE) preprocessor used in air quality modeling. The carbon dioxide (CO_2) post-processor allows users to estimate base year and future year emissions of CO_2. The graphical post-processor generates plots as shown in Figure 4 for every unit processed by the tool. The graphical post-processor is the slowest of the current post-processors and takes about 12 hours to complete on a Linux machine for a large scale regional run. However, graphical presentation of data can be helpful in reviewing specific considerations or concerns for regions and particular facilities or units.

Input Files

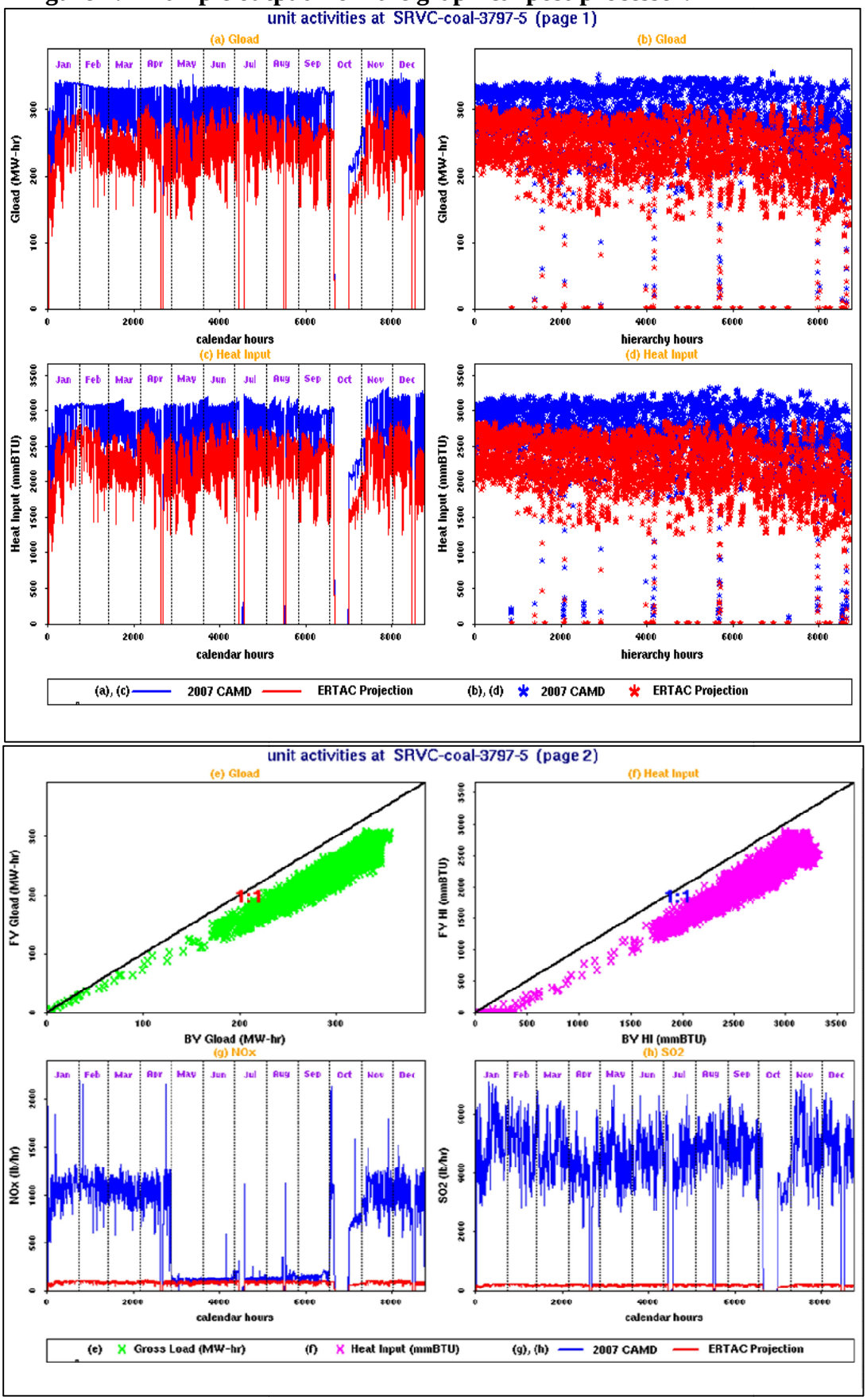
The tool draws information from a number of input files, which the user may adjust according to the informational needs of the specific project. Four files are mandatory for the tool to run: the unit availability file (UAF), the base year hourly CAMD file, the growth rate file, and the input variables file. Other input files include the controls file, the seasonal controls file, the nonCAMD hourly file, the state total file, and the group total file.

<u>UAF (ertac_initial_uaf.csv)</u>

The UAF is a table of every unit that reports to CAMD in the base year and that is located in the region the tool is projecting. The tool's preprocessor log refers to this input file as the "ertac_initial_uaf.csv." This file is required for the ERTAC EGU tool to run. The UAF categorizes every unit by location, fuel/unit type, and status (new, existing, etc). State staff offer significant input into this file, including information such as retirement dates for existing units or fuel-switch information. State staff may use the UAF to limit the future annual operation of a unit or to adjust unit characteristics so that future year operations are appropriately represented. Within the UAF, states may also label units as not EGUs (non-EGUs) in situations where the unit should not be projected using electrical generating utility growth factors. Units must appear in the UAF for the tool to generate results for that unit. Information for existing units originates in CAMD, the National Electric Energy Data System (NEEDS) database, the Energy Information Agency (EIA) Form 860, and North American Electric Reliability Corporation (NERC) data.

The UAF also contains line items for NPUs, the units that state staff believe will be available for future year activity. The information on NPUs originates from permit applications or other information supplied by unit owners for state use.

Figure 4: Example output from the graphical post-processor.



Base Year Hourly Data (camd_hourly_base.csv)

This file contains hourly generation and emissions data extracted from EPA's CAMD continuous emissions monitoring (CEM) database. This file is required for the ERTAC EGU tool to run. The preprocessing log refers to this data file as the "camd_hourly_base.csv" file. This file contains hourly data reported in electronic format under 40 CFR Part 75 for approximately 4,800 fossil fuel fired units. Most of these units are larger than 25 megawatts. CAMD data is of high quality as it is certified to ±10%.[14] Therefore these data provide an excellent basis for temporal activity and emissions profiles for each reporting unit. Data elements include activity (heat input, gross load) and emissions (NO_X, SO_2, and CO_2) as well as other information. The CONUS 2.3 and 2.4 efforts rely on the 2011 CAMD data for base year information. States within the ERTAC EGU workgroup have used 2012 CAMD data as a base year for other regional efforts such as greenhouse gas analyses.

Growth File (ertac_growth_rates.csv)

The growth file is a required input file for the ERTAC EGU tool. It consists of a table of regional growth factors for annual and peak growth as well as other growth-related inputs. The preprocessing log refers to this file as the "ertac_growth_rates.csv" file. NERC estimates are the basis for peak growth rates. The EIA Annual Energy Outlook (AEO) is the basis for the annual growth rates although some states are examining the use of information provided by utilities in place of the AEO information. AEO 2014 is the basis for the CONUS 2.3 and 2.4 efforts. The growth file also specifies the base year and the future year for the run. For each region and fuel/unit type combination listed in the UAF, the growth file must contain a complete entry. Users should note that the annual growth rate prescribed in this file is the basis for future year activity for that region and fuel/unit type. The section entitled Growth Methodology explains this concept in more detail.

Input Variables File (ertac_input_variables.csv)

This file is a table of variables that specifies the projection year and allows customization of certain regional parameters such as the size and location for new units in a projection run. This file is required for the ERTAC EGU tool to run. The preprocessor log refers to this file as the "ertac_input_variables.csv" file. This file must contain a line with complete input variable information for each region and fuel/unit type listed in the UAF.

Controls File (ertac_control_emissions.csv) and Seasonal Controls File (ertac_seasonal_controls_file.csv)

These files contain information regarding future year emission rates and control efficiencies for units listed in the UAF. The preprocessor log refers to the controls file and the seasonal controls file as the "ertac_controls_emissions.csv" file and the "ertac_seasonal_controls_file.csv" file, respectively. If a unit appears in the UAF but not in either of these two files, the tool makes the following assumptions for units with base year data:

- The unit will operate in the future year with an SO_2 emissions rate equivalent to the base year annual average, in pounds per million British thermal units (lbs/mmbtu).
- The unit will operate in the future year ozone season with a NO_X emissions rate equivalent to the base year ozone season average, in lbs NO_X/mmbtu.

- The unit will operate in the future year non-ozone season with a NO_X emissions rate equivalent to the base year non-ozone season average, in lbs NO_X/mmbtu.

If the user supplies no information in these files for a new unit, the tool assumes that the SO_2 and NO_X emissions are equivalent to those representing clean units in that particular region and fuel/unit type. The user may modify the stringency of these values for new units in the input variables file.

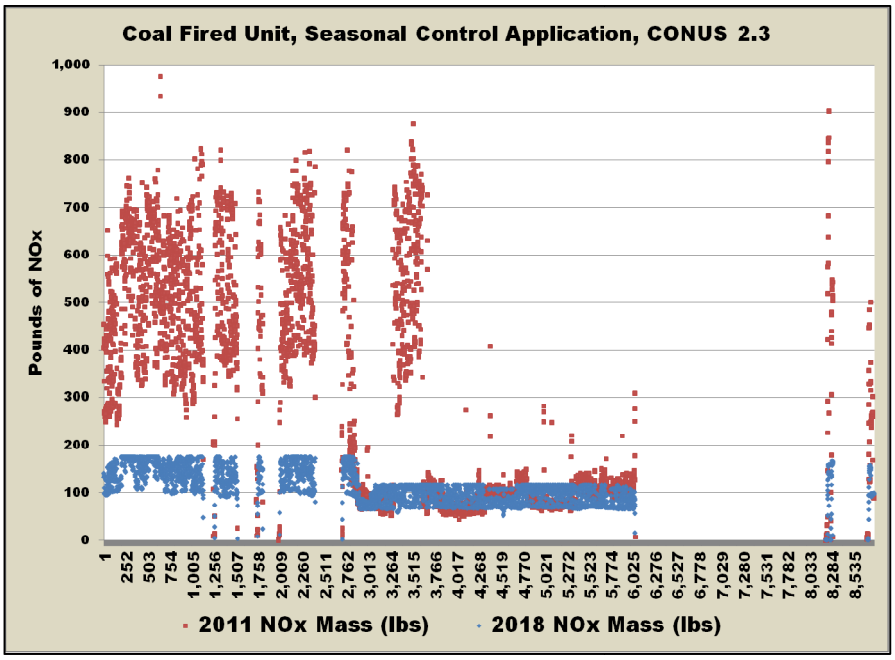
Data supplied by the user in the controls and seasonal controls file will modify these assumptions. The controls file is best suited for year round application of future year emission rates. The seasonal controls file is an optional input file. This file allows the user to enter data for one year, where the emission rates are specific to a portion of the year, and apply that seasonal emissions rate profile to all future estimations beyond the start year. Table 1 provides an example of this type of state input for a specific unit, instructing when various controlled rates should apply for that unit.

Table 1: Unit emissions description.

Time Periods Beginning 2013	Emission Rate
January 1 through April 30	0.10 lbs NOx/mmbtu
May 1 through September 30	0.066 lbs NOx/mmbtu
October 1 through December 31	0.10 lbs NO_X/mmbtu

This information is the basis of the unit's data in the seasonal controls input file. Figure 5 shows the results derived from these emission rate inputs. Within this figure, the color red depicts the 2011 NO_X mass emissions, and the color blue depicts the estimated 2018 NO_X mass emissions. The unit had a base year 2011 ozone season NO_X rate of 0.1147 lbs/mmbtu and a 2011 nonozone season NO_X rate of 0.3789 lbs/mmbtu. The unit is well controlled, and a NO_X limitation of 0.10 lbs/mmbtu became federally enforceable in 2013. The state expects the unit to run the control device beneath that value during the ozone season (May through September) in future years. The value chosen for the ozone season, 0.066 lbs NO_X/mmbtu, is representative of current unit operations based on more recent CAMD data. The unit is located in an area that has historically monitored ambient ozone concentrations above federal standards. Therefore, representing the emissions in the future year from this unit as accurately as possible with known data is important to planning staff within that state. The ability to use the seasonal controls file in this manner may be of value to planners and modelers for units with large emissions that are located in areas expected to experience air quality at or near federal standards.

Figure 5: Seasonal controls, CONUS 2.3.



NonCAMD Hourly Data (ertac_hourly_noncamd.csv)

This file allows the user to append additional data to the base year hourly data file or to overwrite existing data in the base year hourly data file with updated information. The file is not necessary for the tool to run. The preprocessor log refers to the file as the "ertac_hourly_noncamd.csv" file. One use for this file is to append additional data to the base year hourly data file. Users may want to include units that do not report to CAMD in the tool's output. If hourly data is available in the CAMD format, the user may include the hourly data in this file. Including the hourly data in this file and the necessary unit data in the UAF will allow the tool to process the nonCAMD unit. Another use for this file is to update the information in the base year hourly data file. For example, the user may update the reported gross load information if the reported gross load underestimated actual power produced. The section entitled CAMD Data Updates provides more information on how users may use this file to adjust base year hourly CAMD data.

State Total File (state_total_listing.csv) and Group Total File (group_total_listing.csv)

These files allow the user to provide state-specific or region-specific totals for SO_2 and NOx emissions in a variety of future years. The preprocessor log refers to the state total file and the group total file as state_total_listing.csv and group_total_listing.csv, respectively. These are not required input files, and the tool will project future year estimates without their inclusion. When the files are included, the tool will create a comparison output file that automatically sums the emissions from the specified areas and compares that total to the value placed within the input file. However, data in these files do not influence either the power assigned to any unit or the emission rate of any unit. To change a unit's future year activity or emission rate, the user must provide unit-specific information in the UAF or the controls file.

Growth Methodology

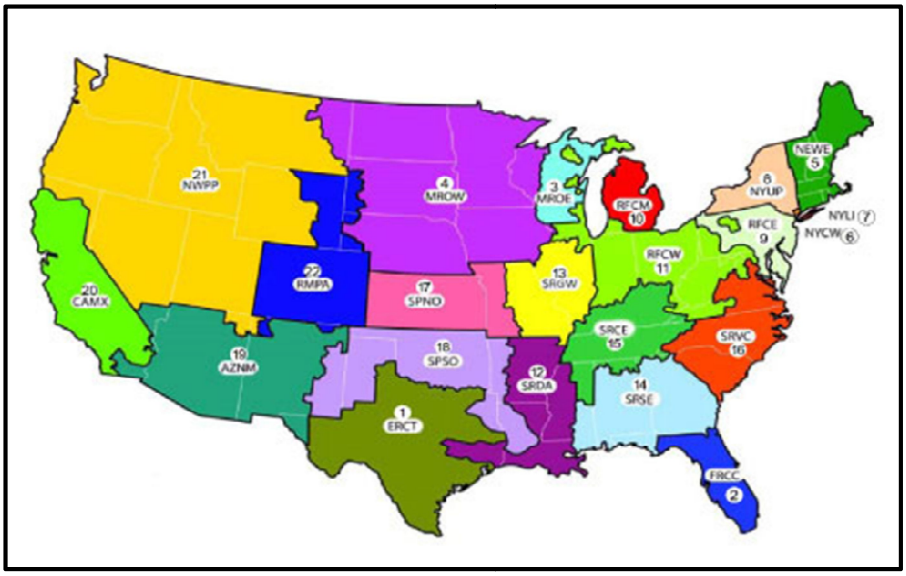
The tool develops hour specific growth rates based on several factors. These factors include the annual and peak growth rates assigned by the user in the growth rates file, the hourly base year generation profile for the region and fuel/unit type, and the transition points between peak and annual growth rates that the user assigns in the growth rates file.

Growth Rate Development

The ERTAC EGU workgroup has a growth subgroup that develops the annual and peak electrical generation growth factors for use in the CONUS ERTAC EGU tool runs. The electrical generation growth is delineated by geographic region and fuel/unit type. Figure 6 provides the boundaries used for the CONUS2.3 reference case runs. Regions and fuel/unit types are not hardwired into the tool. Instead, the regions and their characteristics are part of the input files. The UAF assigns a region and fuel/unit type to each unit, and the growth rate file specifies region and fuel/unit type growth rates as well as hours in the year used to transition from peak growth rates.

The basis for the annual growth rate information is the EIA AEO. For CONUS2.3, the growth subgroup used AEO2014 information to estimate regional future year demand. AEO documentation provides information on many fuel types. For ERTAC EGU tool purposes, the subgroup used information for coal, oil, and natural gas and further divided natural gas into boiler gas, simple cycle

Figure 6: Regional boundaries for CONUS2.3.



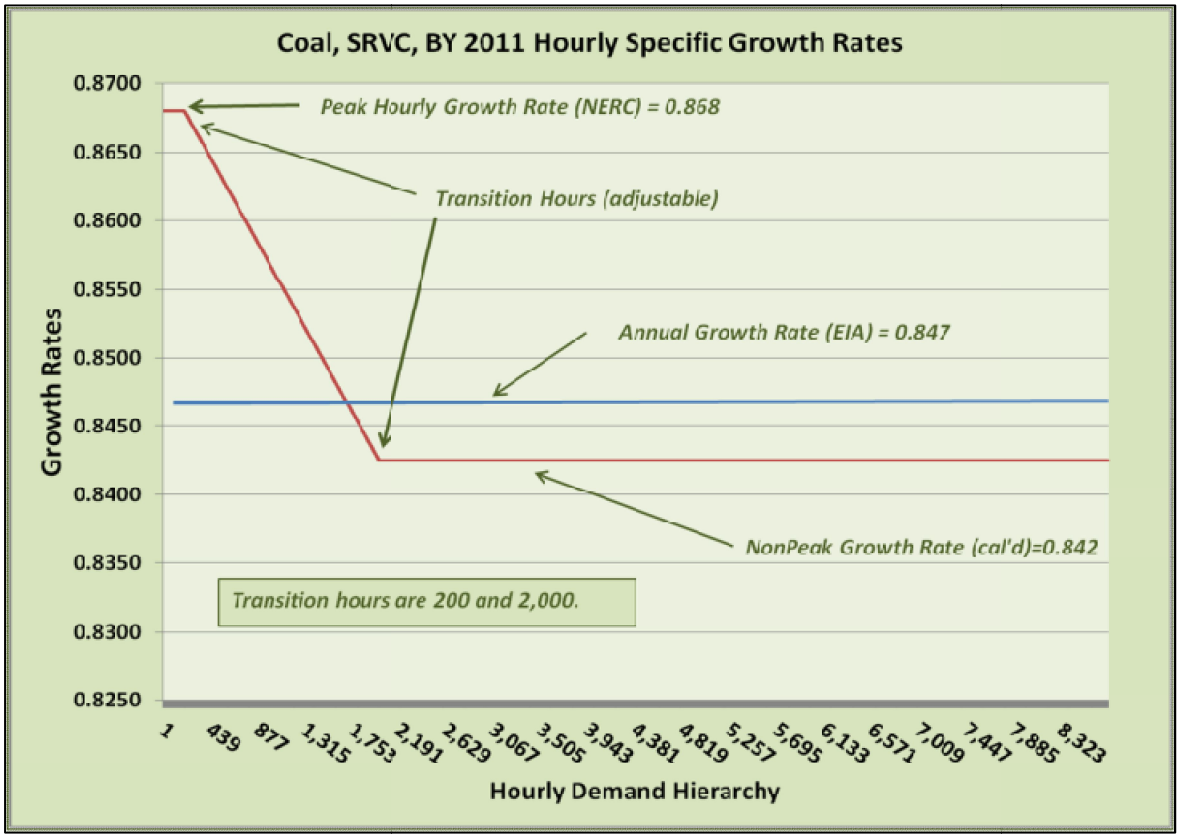
gas, and combined cycle gas operations. Dividing future year projections by base year demand yielded the growth rates for each region and fuel/unit type. The basis for the peak growth rate information is NERC 2013 projections. The subgroup used information in the NERC Capacity and Demand Schedule 1B to develop the peak growth rates by region and fuel/unit type.

The regional boundaries used by EIA and NERC are similar but not identical. The ERTAC EGU growth subgroup elected to use the EIA regions as the primary regional scheme for the tool and assigned a "best fit" NERC regional growth factor to each EIA region.

Growth Rate Application within the Tool

The first step in the growth methodology is the assignment of nonpeak growth rates. Figure 7 provides a conceptual graph of nonpeak growth rate development.

Figure 7: Transition hours and nonpeak rates.



The tool ranks base year hours using power generated by a specific fuel/unit type in a region. Hour 1 is the hour with the most power generated, and hour 8,760 is the hour with the least power generated in that region. This order is called the hourly demand hierarchy. The tool applies the peak growth rate to hours 1 through the first transition period, which the user defines in the growth rate input file under the column called, "Transition Hour Peak to Formula." In Figure 7, the growth rates input file defines this transition hour at 200. The tool calculates a specific growth rate for each hour within the transition period, the hours between the first transition hour and the second transition hour, using a linear formula. The user defines the second transition hour in the growth rates file under the column called, "Transition Hour to NonPeak." The tool calculates a nonpeak growth rate and applies that growth rate to the hour after the second transition hour assigned by the user (transition to nonpeak) and to every hour thereafter. In Figure 7, the transition to nonpeak value supplied by the user is 2,000. In this case, the nonpeak growth rate applies to every hour from 2,001 through 8,760. The formula for determining the nonpeak growth rate is in Equation (1).

Equation (1): $$(AGR) \times \left(\sum_{1}^{8,760} BYDemand_i\right) = (PGR) \times \left(\sum_{1}^{PtoT-1} BYDemand_i\right) + \sum_{PtoT}^{TtoN}(THGR_i \times BYDemand_i) + (NPGR) \times \sum_{TtoN+1}^{8,760} BYDemand_i$$

where

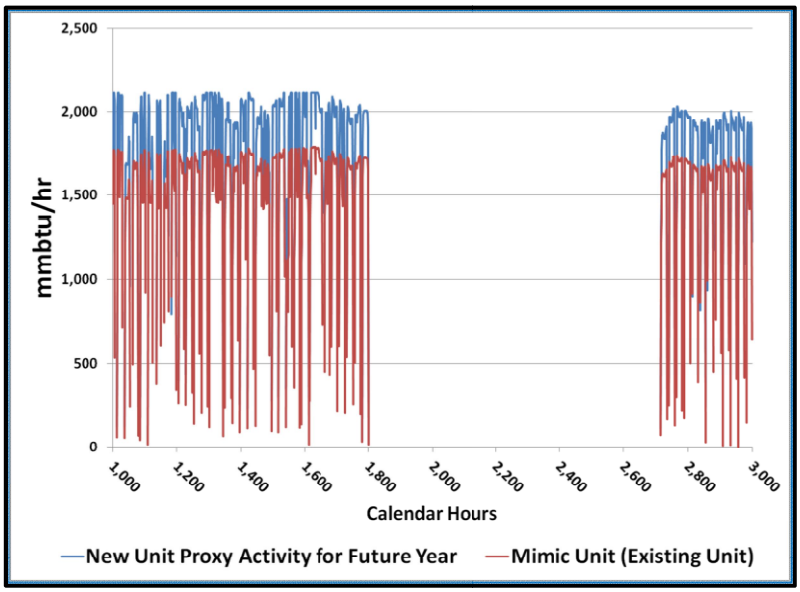
AGR	= Annual growth rate supplied by user in growth rates file
$BYDemand_i$	= Hourly base year demand in hour i for all units in that region and fuel/unit type
PGR	= Peak growth rate supplied by user in growth rates file
PtoT	= First transition hour supplied by user in growth rate file (peak to transition hour)
TtoN	= Second transition hour supplied by user in growth rate file (transition to nonpeak hour)
$THGR_i$	= Hourly transition period growth rate in hour i, calculated from a linear application using the peak growth rate, the nonpeak growth rate, and the transition hours
NPGR	= Nonpeak growth rate

In Equation (1), the nonpeak growth rate appears in both the second and third operations in the formula so that an algebraic solution to the formula for nonpeak growth rates is not possible. The tool uses a secant root method to estimate the nonpeak growth rate for each region and fuel unit type. The equation also shows that the annual growth rate and the sum of the hourly base year demand in that fuel\unit type drive the overall annual activity projected for the future year.

The next step in determining hourly growth rates is the allocation of power to NPUs and GDUs, which are new units that do not have base year profiles. To generate a representative base year profile for NPUs and GDUs, the tool uses two methods, one for coal-fired units and one for all other fuel/unit types. For coal-fired units, users set a fixed percentage of capacity to be assigned to new units on an hourly basis within the input variables file in the column labeled "Proxy % (for coal only)." For example, if a new coal-fired unit is rated at 600 MW, and the user sets the value in this column to 50, the new coal-fired unit will initially be set to run at 300 MW in every hour of the future year. As needed, the unit may generate more power on hours where other units may be at maximum capacity. This methodology reflects the base load nature of coal-fired units.

For units other than coal-fired units, the user sets a percentile value in the inputs variable file column called "New unit percentile for placement in the Unit Allocation Hierarchy." This percentile determines which existing unit will be used as a mimic unit for developing an initial profile of activity for the new unit. The initial profile of gross load and heat input for the new unit replicates the levels seen in the base year for this existing unit. Therefore, the new unit receives initial loading that reflects the operations of a similar unit in that region and fuel/unit type bin. Figure 8 provides an example of this function. The figure shows base year activity for the existing unit that is mimicked during calendar hours 1,000 through 3,000 (red line) and the future year power provided initially to a new unit (blue line) during that same period. The new unit is larger than the mimic unit so that all hours of activity are scaled proportionally. Using a unit that is located within the same region as the new unit allows the estimated future year profile of the new unit to reflect at least partially the base year meteorology experienced by other units in that region. The new unit also receives a profile that includes appropriate diurnal variations. If the user judges the mimic unit to be unsuitable for use in approximating the future year profiles of new units, the user may adjust the percentile value in the input variables file to select a different unit. As with coal, in hours where existing unit power demand exceeds capacity, the tool may also assign new units additional generation, up to the new unit's capacity.

Figure 8: New unit power example.



The tool next adjusts each hour's growth rate value for power generated in that hour by new units and power generated in that hour by retiring units. Equation (2) provides this formula.

Equation (2): $$AFYGR_i = \frac{(FY\ Gen_i - NU\ Gen_i)}{(BY\ Gen_i - RU\ Gen_i)}$$

where

$AFYGR_i$ = Adjusted future year growth rate for hour i

$FY\ Gen_i$ = Future year generation for hour i calculated from the sum of the base year generation for that hour multiplied by the hour specific growth rate for that hour calculated in Equation (1)

$NU\ Gen_i$ = Generation in hour i supplied to new units to approximate a reasonable profile of activity

$BY\ Gen_i$ = Base year generation for hour i calculated from the sum of the base year generation for that hour for all units in that region and fuel/unit type

$RU\ Gen_i$ = Base year generation for hour i for all units that retire by the future year in that region and fuel/unit type

For hour i, the tool multiplies the base year generation from every existing unit that operates in the future year by AFYGRi. Equation (3) provides this simple operation.

Equation (3): $FY\ Hourly\ Gross\ Load_{i,j} = AFYGR_i \times BY\ Hourly\ Gross\ Load_{i,j}$

where

FY Hourly Gross $Load_{i,j}$	= The future year hourly gross load for hour i and for unit j in a particular region and fuel/unit type
$AFYGR_i$	= Adjusted future year growth rate for hour i calculated from Equation (2)
BY Hourly Gross $Load_{i,j}$	= The base year hourly gross load for hour i and for unit j in a particular region and fuel/unit type

The last step of the process is to check that unit hourly generation and unit annual generation to that point in the year do not exceed any unit's capacity and utilization limitations. In situations where the power supplied to a unit does exceed such limitations, the tool redistributes the power to other units in the region and fuel/unit type. In this manner, no unit operates above its maximum thresholds as provided by information in the UAF and the hourly base year data.

APPLICATIONS OF THE ERTAC EGU TOOL

The ERTAC EGU workgroup designed the tool specifically for air quality planning and modeling. The Mid-Atlantic Regional Air Management Association (MARAMA) is currently using the results of the tool in air quality assessments for SIP submittals in the mid-Atlantic region. States and MJOs have also used the tool to generate data for other types of analyses. These analyses include estimating impacts of upcoming rules and alternative growth rates, evaluating the effects of improving base year CAMD data, creating "what if" analyses for retirements and fuel-switches, and creating preliminary analyses for CO_2 emissions and greenhouse gas rules.

ERTAC MATS Analysis

EPA published the Mercury and Air Toxics (MATS) rule in the *Federal Register* on February 16, 2012 (77 FR 9304).[15] This rule regulates the emissions of acid gases and mercury from coal-fired and oil-fired EGUs. The compliance date for the MATS rule is April 2015.[16] Controlling acid gases has the co-benefit of reducing SO_2 emissions, and the rule offers regulated entities the option of using an alternative compliance limit of 0.20 lbs SO_2/mmbtu to demonstrate compliance with acid gas requirements.[17]

The 2013 $PM_{2.5}$ NAAQS has a moderate area compliance date of six years after designation[18] so that the effects of MATS must be considered in air quality plans for this $PM_{2.5}$ standard. States and MJOs are very interested in what level of SO_2 controls the EGU sector may experience due to the MATS rule. The ERTAC EGU workgroup developed a regional analysis to examine some of the questions concerning the application of MATS to future year EGU inventories. Initially, the analysis consisted of five separate cases for base year 2011 projected to three difference future years (2017, 2018, and 2020) using the CONUS2.0 input files. After consideration by state staff, the analysis expanded to include three additional runs of year 2018 based on the CONUS2.2 input files. For base year 2011, the scope of this work entailed a total of 18 tool runs, which were accomplished in a two week period.

MATS Compliance in ERTAC Input Files

The ERTAC EGU workgroup schedules comment periods two to four times annually for a 30-day period to allow states to provide changes to inputs for their EGU inventories. As a result, the input files for the tool are generally no more than six months out of date, and these files contain reasonably current information on EGU plans and state expectations of emissions.

The ERTAC MATS analysis examined the input files using the alterative compliance standard of 0.2 lbs SO_2/mmbtu to determine which units were MATS compliant in the base year and which units were already expected to be MATS compliant in the future year. Any MATS-applicable unit for which the input files indicate expected future year emission rates less than or equal to 0.2 lbs SO_2/mmbtu were considered compliant. The use of 0.2 lbs SO_2/mmbtu is a conservative approach for determining compliance since unit owners may also choose to demonstrate compliance directly with the MATS rule acid gas limitations rather than meeting 0.2 lbs SO_2/mmbtu. Compliance with the acid gas limitations will provide SO_2 co-benefits; however, these co-benefits may not lower the unit's SO_2 emission rate to 0.2 lbs SO_2/mmbtu or less. Therefore, some units deemed noncompliant in this analysis may actually be compliant with the standard. As Table 2 shows, the percentage of base year coal capacity applicable to MATS that is compliant with the standard of 0.2 lbs/mmbtu is increasing as states learn of facility compliance plans and supply that information to ERTAC.

The percentage of base year coal capacity that is compliant, as listed in Table 2, is calculated by dividing the sum of the capacity of existing units meeting 0.2 lbs SO_2/mmbtu and the retired coal capacity in the future year by the base year coal capacity. For example, the value of 60.8% for CONUS 2.0 is calculated by Equation (4).

Equation (4): $60.8\% = 100 \times {(187{,}756 + 45{,}698)}/{383{,}827}$

As of July 2013, data provided by states to the ERTAC EGU workgroup showed a rate of compliance just under 61%, and this value increased to just over 66% by September 2014. The September 2014 input files supported the CONUS2.3 reference case.

Table 2: MATS compliance in ERTAC EGU input files.

Version Number:	2.0	2.1L1	2.2	2.3
Data As-Of Date	7-18-2013	3-3-2014	4-4-2014	9-24-2014
BY Coal Capacity	383,827 MW	383,384 MW	383,851 MW	383,656 MW
BY Coal Capacity Retired by 12/31/2018	45,698 MW	50,128 MW	56,898 MW	63,884 MW
Gasified Capacity as of 12/31/2018	9,193 MW	9,082 MW	9,063 MW	14,929 MW
BY SO_2 from Retired Coal	1,040,354 tons	1,170,015 tons	1,251,732 tons	1,335,231 tons
Existing Units in FY Meeting 0.2 lbs/mmbtu	187,756 MW	190,532 MW	189,304 MW	190,226 MW
% BY Capacity Compliant	60.8%	62.8%	64.1%	66.2%

ERTAC EGU Approach for MATS Compliance of "Non-Compliant" Units

As noted above, the MATS rule offers a number of approaches to demonstrate compliance, and most do not involve limiting SO_2 emissions. Using state and utility feedback, the ERTAC EGU workgroup developed scenarios to examine how assumptions about controls may affect the future year

emissions from the remaining noncompliant future year coal capacity. The remaining coal capacity is described herein as non-compliant, however, as noted above, this analysis used a very stringent mechanism to determine which units would be deemed compliant. Some facilities may be compliant with MATS but determined here to be non-compliant due to the use of the alterative compliance limit of 0.2 lbs SO_2/mmbtu as the compliance factor.

Initially, the ERTAC EGU workgroup analyzed results from five scenarios applied to CONUS2.0 input files. Table 3 describes each of these five scenarios. After review and discussion, the Lake Michigan Air Directors Consortium (LADCO) recommended updating the analysis to re-run scenarios 2 and 4 using CONUS2.2 input files. Additionally, LADCO suggested one other scenario based on state and industry feedback. Table 4 provides information on the MATS scenarios applied to the CONUS2.2 input files.

Table 3: Five scenarios used in the CONUS2.0 MATS analysis.

Scenario #	Scenario Name	Scenario Description
1	Flat rate option	This scenario applied a 0.2 lbs/mmbtu SO_2 emission rate to any coal fired unit that operates in the future year above that rate.
2	Capacity option	This scenario applied 90% or 98% control to any unit not meeting 0.2 lbs/mmbtu in the future year and having a capacity of at least 400 MW. Smaller units with non-compliant future year rates had their rates reduced to 0.2 lbs/mmbtu SO_2.
3	Emission rate option	This scenario applied 90% or 98% control to any unit not meeting 0.2 lbs/mmbtu in the future year and with an emission rate of more than 1.0 lbs/mmbtu SO_2 in the future year. Units with an emission rate between 0.2 and 1.0 lbs/mmbtu SO_2 in the future year received a future year emission rate 0.2 lbs/mmbtu SO_2.
4	Retirement option	This scenario retired any unit with a capacity of less than 350 MW not meeting 0.2 lbs/mmbtu in the future year. Coal units with a capacity of at least 350 MW and not meeting 0.2 lbs/mmbtu in the future year had a 30% reduction in SO_2 applied in the future year. The 30% reduction in SO_2 accounts for co-benefits from acid gas control strategies.
5	Fuel switch option	This scenario switched any coal unit with a capacity of less than 350 MW not meeting 0.2 lbs/mmbtu in the future year to natural gas. Units with a capacity of at least 350 MW not meeting 0.2 lbs/mmbtu in the FY had a 30% reduction in SO_2 applied in the future year.

Table 4: Three scenarios used in the CONUS2.2 MATS analysis.

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Scenario #	Scenario Name	Scenario Description
2	Capacity option	This scenario applied 90% or 98% control to any unit not meeting 0.2 lbs/mmbtu SO_2 in the future year and having a capacity of at least 400 MW. Smaller units with non-compliant future year rates had their rates reduced to 0.2 lbs/mmbtu SO_2.
4	Retirement option	This scenario retired any unit with a capacity of less than 350 MW not meeting 0.2 lbs/mmbtu SO_2 in the future year. Coal units with a capacity of at least 350 MW and not meeting 0.2 lbs/mmbtu SO_2 in the future year had a 30% reduction in SO_2 applied in the future year. The 30% reduction in SO_2 accounts for co-benefits from acid gas control strategies.
6	Retirement option, reduced control	This scenario retired any unit with a capacity of less than 350 MW not meeting 0.2 lbs/mmbtu SO_2 in the future year. Coal units with a capacity of at least 350 MW and not meeting 0.2 lbs/mmbtu SO_2 in the future year will have a 15% reduction in SO_2 applied in the future year. The 15% reduction in SO_2 accounts for co-benefits from acid gas control strategies used in conjunction with coal containing low amounts of chlorine.

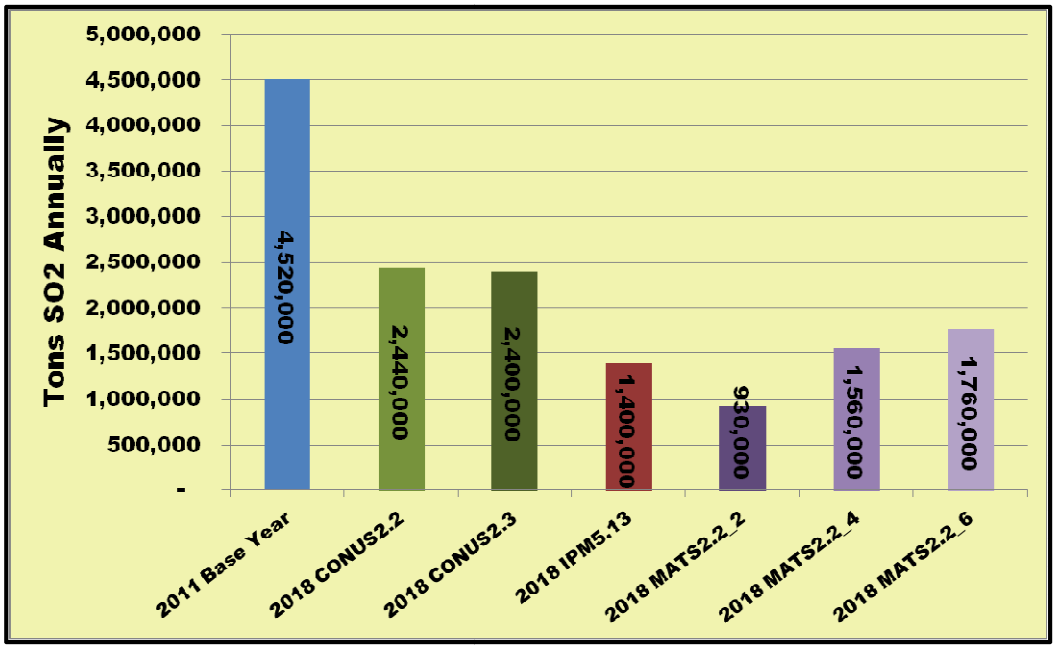
MATS Analysis Results

Generally, the results of the MATS scenarios showed SO_2 emissions in the future year that are somewhat higher than the estimates of SO_2 emissions from EPA's projections. The most stringent of the scenarios applied to CONUS2.2, scenario 2, generated results that were less than those projected by EPA's Integrated Planning Model (IPM), case 5.13. All other scenarios projected more SO_2 emissions

in the future year than did IPM 5.13. Figure 9 compares the 2011 base year total SO_2 emissions from the CAMD reporting units against the 2018 estimates from CONUS2.2 and CONUS2.3 reference case runs and the three MATS scenarios applied to CONUS2.2.

The results also showed that for some regions of the country, application of the scenario assumptions accomplished only small additional SO_2 emission reductions compared to the CONUS reference run. For example, the southeastern region shown in the top half of Figure 10 achieved additional SO_2 emission reductions of only about 13,000 tons annually. However, the Midwestern region shown in the bottom portion of Figure 10 had a greater overall SO_2 mass reduction. This region demonstrated additional SO_2 reductions in the range of 200,000 tons in the future year. The Midwestern region had fewer units with compliant data already provided in the CONUS file inputs than did the southeastern region. Therefore, application of the various scenario assumptions affected more Midwestern units and their emissions. However, due to the MATS assumptions, neither region had significant additional NO_X emission reductions, which are important in reducing ozone formation.

Figure 9: SO_2 emission estimates from various projections.

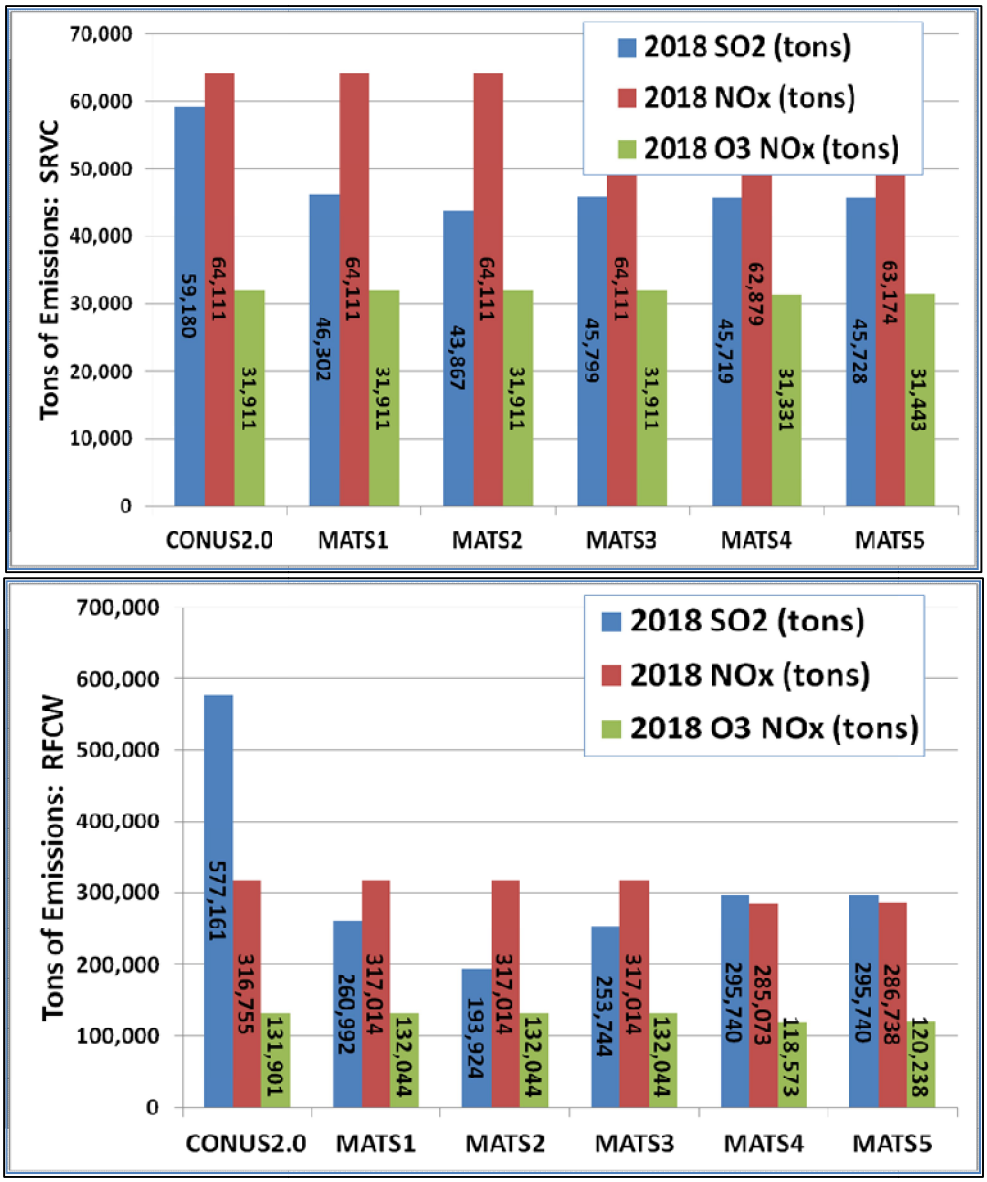


The ERTAC EGU workgroup used the data generated by this case study to make the following conclusions:

- Much of the coal capacity reporting to CAMD already has known plans for MATS compliance, and the CONUS input files for the ERTAC EGU tool reflect this information.
- Further SO_2 emission reductions in future years associated with MATS vary by region.
- EPA estimates of SO_2 emissions in IPM 5.13 outputs may overestimate the reductions associated with MATS.
- Application of the MATS rule does not seem to generate significant additional NO_X reductions.

In this analysis, the ERTAC EGU workgroup successfully used the tool to apply different assumptions to input data and to create results for several future years. The tool was capable of generating the results from 18 runs in approximately two weeks, and input files were flexible enough to impose a variety of assumptions. States provided feedback that these results were helpful in evaluating the overall co-benefits that might be expected from the MATS rule beyond the reductions already noted in the future year from the CONUS reference case runs.

Figure 10: Regional MATS results.



Alternative Growth Rates

The ERTAC EGU workgroup and regional staff have performed a number of evaluations on the use of alternative growth rates. AEO provides conservative estimates of future year growth; however, states or regional entities may have more recent information or may have information that reflects regional characteristics more appropriately than the AEO data. Use of the ERTAC EGU tool to update projections based on alternative growth rates is a relatively simple matter. Users are able to run a CONUS projection for a future year with alternative growth rates in less than 24 hours, using computers with reasonable capabilities.

<u>High/Low Case Study</u>

The ERTAC EGU workgroup used the CONUS 2.1L1 reference case input files to examine the impact of applying growth rates based on AEO case studies for costs of fuels and changes in natural gas

availability. One scenario in this case study used a low oil and gas resource case from AEO. This scenario assumed that delivered natural gas prices to the electric power sector were significantly higher in future years, as compared to the assumptions in the AEO reference case. The second scenario was a high oil and gas resource case. This scenario assumed that natural gas prices were significantly lower in future years, as compared to the assumptions in the AEO reference case. The case study applied these new sets of growth rates to future year estimates using base years 2007 and 2011. The future years analyzed were 2018 and 2020. The case study used eight sets of input files to create the outputs for the analysis.

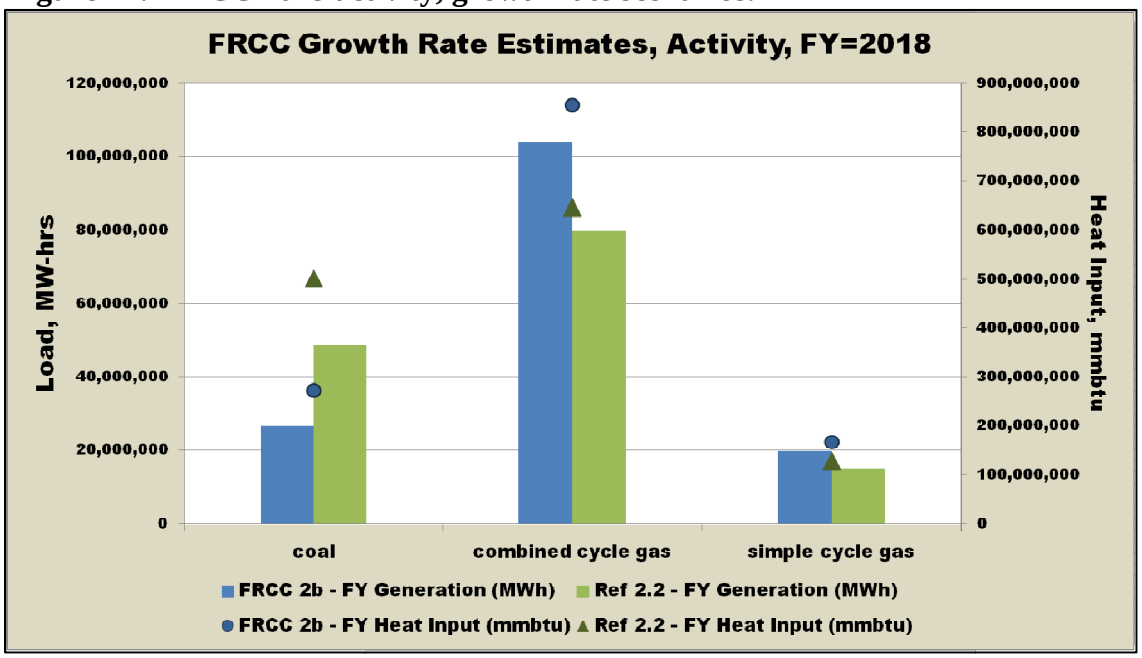
FRCC Evaluation

The FRCC analysis used CONUS2.2 input files and multiple AEO growth rates to estimate projections from different economic scenarios. Table 5 provides the growth rates used in the CONUS2.2 reference run and the FRCC high natural gas availability run. Figure 11 provides a comparison of activity estimates in the future year derived from the various growth rates. Figure 11 denotes the future year activity projected by the growth rates for CONUS2.2 listed in Table 5 using green bars and triangles. Activity projected by run 2b reflects the application of alternative growth rates, and Figure 11 shows this information using blue bars and circles.

Table 5: Growth rates used in FRCC evaluation.

Fuel-Unit Type	AEO 2013 CONUS2.2		AEO2013 High Gas	
	Annual	Peak	Annual	Peak
Coal	0.962	0.962	0.522	0.526
Combined Cycle	0.894	0.900	1.165	1.174
Oil	0.093	0.094	0.071	0.071
Simple Cycle	0.894	0.900	1.165	1.174

Figure 11: FRCC 2018 activity, growth rate scenarios.



CAMD Data Updates

Two regions, FRCC and RFCM, have evaluated the impacts on activity and emissions from updating reported gross load in the base year hourly CAMD file. Some combined cycle units may underreport hourly gross load to the CAMD database due to ambiguities within the 40 CFR Part 75 monitoring guidance documents.[19] In some instances, unit owners choose not to report gross load associated with the steam generators in combined cycle systems to the CAMD database. In these instances, gross load for facilities with these units as reported to CAMD may be significantly lower than net load reported for these facilities to the EIA.

Figure 12 shows an example of 2011 data for a hypothetical facility that reported approximately 100,000 megawatt-hours (MWh) of net load in their EIA 923 submittal but only 74,500 MWh of gross load to the CAMD data base for the same year. Using the nonCAMD hourly file, users of the ERTAC EGU tool may update the gross load data in the base year hourly data file using the resulting ratio of 1.34. The reported gross load for each hour is multiplied by a ratio of 1.34 to account for the underreported load, as shown in the columns called "GL Original (MW)" and "GL Final (MW)." Using this ratio may result in the gross load continuing to be somewhat underestimated since EIA data is net load while CAMD is gross load. However, the updated information is a significant improvement.

Figure 12: Example adjustment to gross load data.

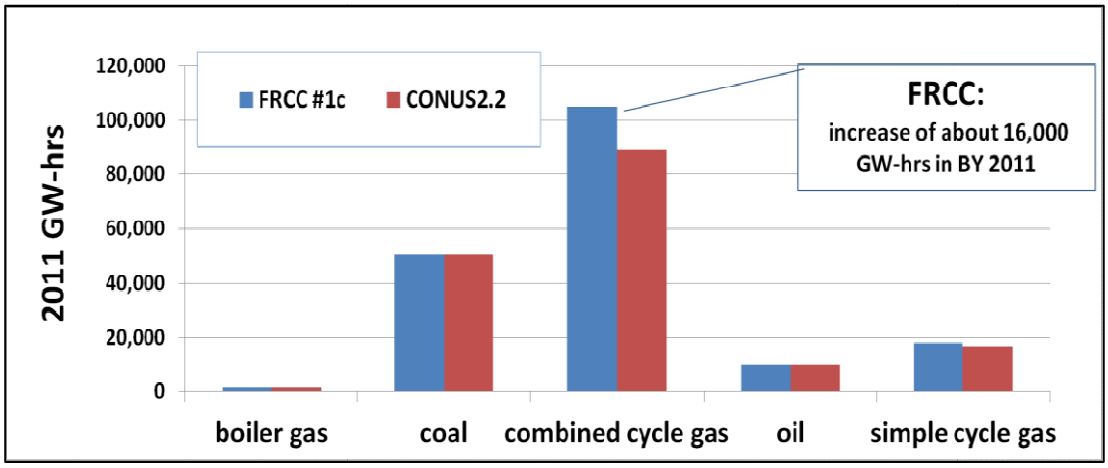
Data Source	MWh
2011 EIA 923 Form	100,000
Total 2011 Gen GL, CAMD	74,500
Ratio	1.34

State	Name	ORIS	ID	Date	HR	GL Original (MW)
XX	Plant A	37XX	1	1/2/2011	1	100
XX	Plant A	37XX	2	1/2/2011	1	178
XX	Plant A	37XX	3	1/2/2011	1	200

State	Name	ORIS	ID	Date	HR	GL Final (MW)
XX	Plant A	37XX	1	1/2/2011	1	134
XX	Plant A	37XX	2	1/2/2011	1	239
XX	Plant A	37XX	3	1/2/2011	1	268

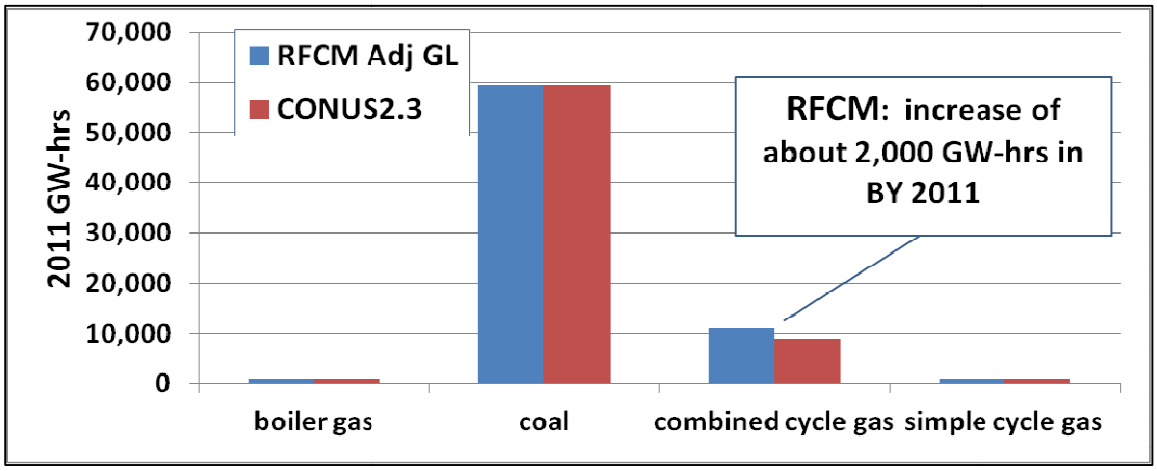
Michigan (RFCM) and Florida (FRCC) identified units reporting to CAMD that may have underreported 2011 gross load based on comparisons to 2011 EIA information. After developing ratios for each facility, the gross load in the hourly data file was modified using the nonCAMD hourly input file, and the ERTAC EGU tool created projections to 2018 for these regions. Figure 13 and Figure 14 show how these adjustments affected the 2011 base year activity in each region.

Figure 13: FRCC base year 2011 gross load adjustments.



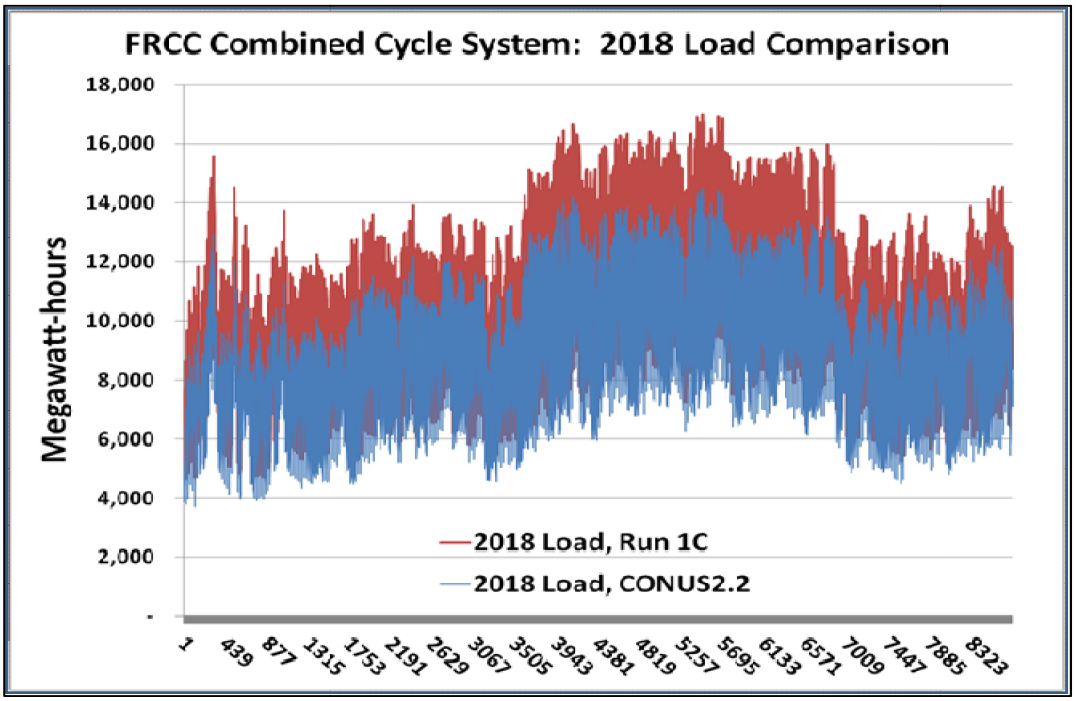
FRCC, seen in Figure 13, had more combined cycle units and combined cycle utilization in 2011 than did RFCM. Adjustments to gross load increased combined cycle output by approximately 16,000 gigawatt-hours (GWh). RFCM, seen in Figure 14, had fewer combined cycle units and less overall combined cycle utilization than did FRCC. The adjustments to base year data increased combined cycle output by approximately 2,000 GWh.

Figure 14: RFCM base year 2011



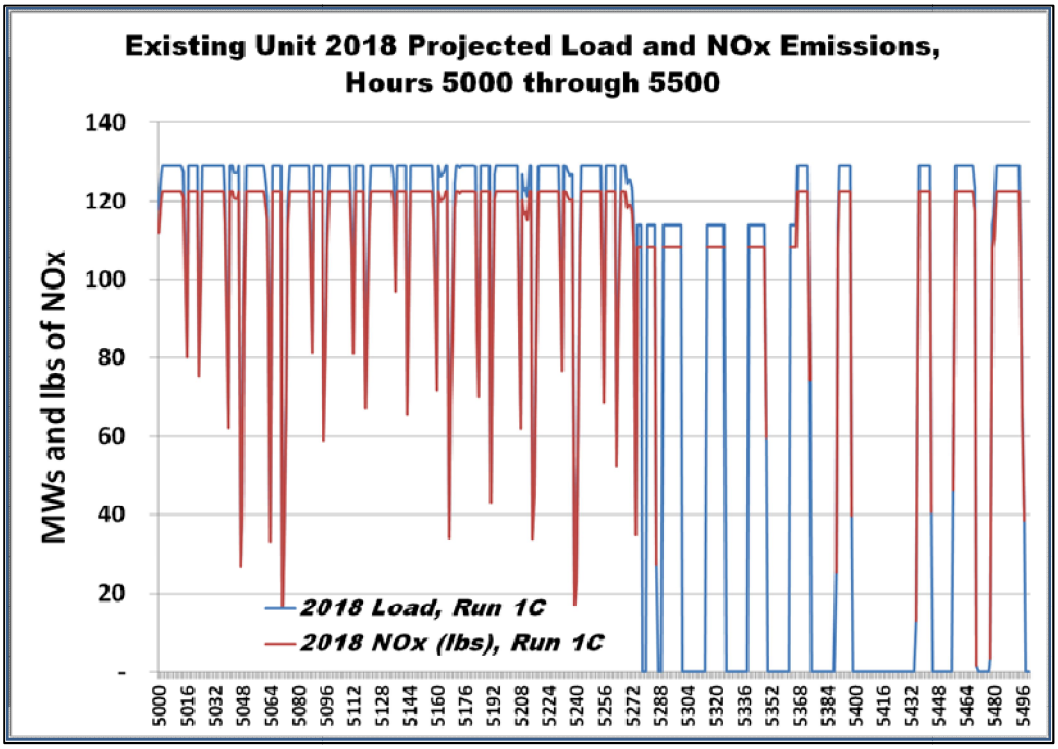
Output from these runs provided insight into how adjusting the gross load for select units affected regional power projections as well as unit specific projections. Figure 15 shows the 2018 future year activity estimate for gross load in the FRCC combined cycle system from January 1 through December 31. Run 1C, shown in red, used adjusted gross load information while the CONUS2.2 run, shown in blue, used the gross load information as reported to CAMD. The graph in this figure demonstrates that hours during the summer months, roughly calendar hour 3,000 through calendar hour 6,500, appear to be more heavily affected by the adjustments than other hours of the year.

Figure 15: FRCC 2018 combined cycle load comparison.



The ERTAC EGU tool offers the ability to review data on a regional level, as shown in Figure 15. It also offers users the ability to evaluate the effects of input updates on any unit's hourly activity. For example, Figure 16 provides the hourly output for an existing combined cycle unit within the FRCC system, showing the projected load and NO_X emissions from this unit for a 500 hour period during the summer months. This transparency allows users to understand the effects of changes to inputs on scales ranging from the annual activity within an entire system down to one unit in a single hour.

Figure 16: FRCC hourly activity, one unit.

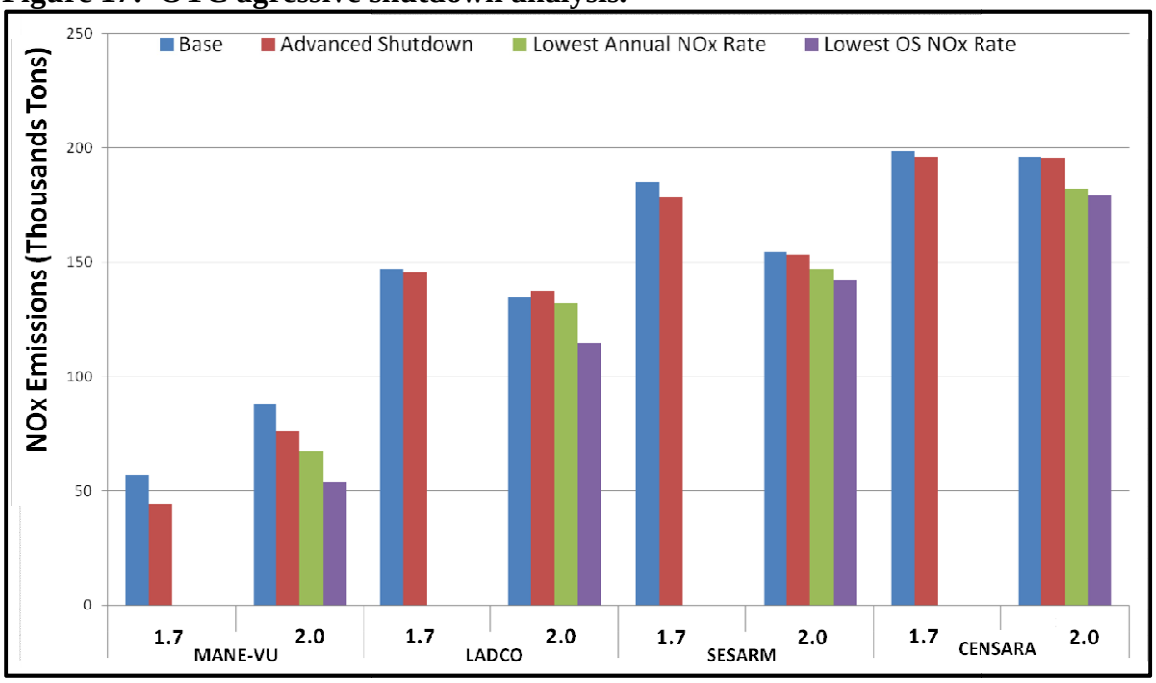


Aggressive Retirement Scenario

States must use caution when including retirements and other changes to units in the ERTAC EGU tool input files. Retirements and fuel switches that reduce emissions are beneficial in future year air quality analyses. However, caution is prudent because basing a SIP on a retirement or fuel-switch that does not happen could have negative consequences for the citizens of the area in question and the state responsible for air quality improvement. Generally, states must have more certainty than press releases or other public statements by owners before they submit such changes to the ERTAC EGU workgroup. The Ozone Transport Commission (OTC) compiled a list of potential EGU unit retirements that went beyond the information supplied within the ERTAC input files. The OTC then used the ERTAC EGU tool to estimate the impact of these additional potential retirements.

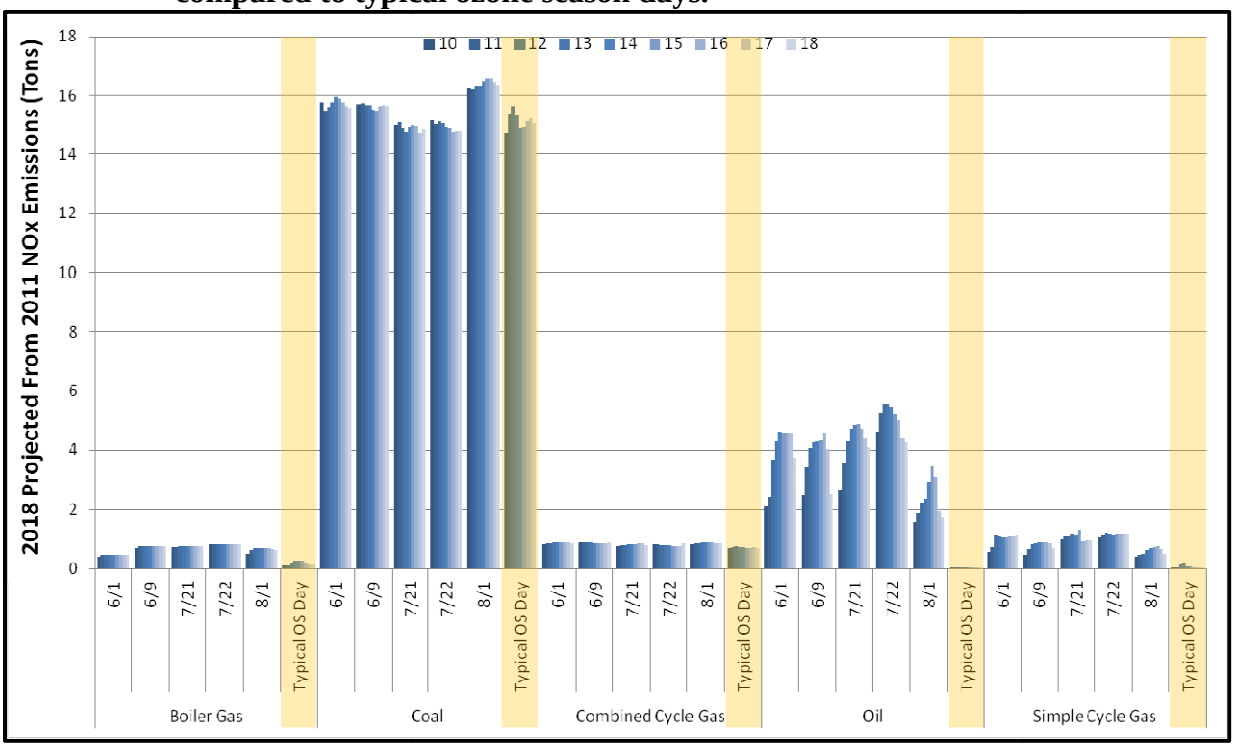
In this analysis, the OTC was also interested in evaluating the effects of lower NO_X emission rates applied to certain units during the future year and how the results might differ from base year 2007 to base year 2011. The organization conducted multiple runs to evaluate these scenarios, as presented in Figure 17. Figure 17 evaluated projections resulting from the use of a 2007 base year and a 2011 base year, labeled 1.7 and 2.0 respectively. The results showed that applying an aggressive retirement scenario did not generate as many emission reductions as did reducing NO_X emission rates. This result may be due to units on the aggressive retirement listing being smaller units that did not run frequently in the base year, and therefore their retirement had limited impact on emissions.

Figure 17: OTC agressive shutdown analysis.



This evaluation also examined emissions from the hours of 10 a.m. to 6 p.m. on selected ozone season peak days in 2018. Figure 18 provides an example of this analysis for RFCE, a mid-Atlantic region. Emissions during the hours 10 a.m. through 6 p.m. of selected high ozone days are compared to emissions from these same hours on a more typical summer day, highlighted in amber. The data are subdivided by fuel/unit type to provide information on fuel utilization during high ozone days.

Figure 18: 2018 NO_X emissions (tons), from 10 a.m. to 6 p.m., ozone season peak days compared to typical ozone season days.



This analysis showed that for some regions like RFCE, oil generation is important on peak demand days. In this example, the OTC demonstrated how the ERTAC EGU tool could be used to evaluate strategies and scenarios to determine which may be most beneficial for the pollutant of concern. Transparent tool results facilitated the evaluation of peak demand days, which correspond to HEDD days, and provided insights into regional factors affecting future year HEDD emissions.

CO_2 Analyses

In 2013 Georgia wanted to determine how states that participate in the Southeastern Modeling, Analysis, and Planning Project (SEMAP) were performing, compared to the Presidential Climate Action Plan's 2009 goal of a 17% reduction in CO_2 emissions by 2020 from a 2005 baseline. As a starting point, Georgia staff used 2005 and 2011 CO_2 emissions reported to CAMD and estimated 2018 CO_2 emissions based on projected 2018 heat input activity derived from the ERTAC EGU tool. Georgia used three approaches to arrive at 2005, 2011, and 2018 CO_2 emissions for each state, using a combination of CAMD data and emission factors. Table 6 provides the breakdown of data used in each method. Table 7 summarizes the results for each SEMAP state and the region as a whole.

Table 6: Georgia assumptions in 2013 CO_2 analysis.

	2005	2011	2018
Heat Input Data, mmbtu	CAMD Heat Input Data	CAMD Heat Input Data	ERTAC EGU Tool Projections, CONUS2.0
CO_2 Emissions, TPY Method 1	CAMD CO_2 Data	CAMD CO_2 Data	State derived CO_2 emission factors from 2005 CAMD data
CO_2 Emissions, TPY Method 2	CAMD CO_2 Data	CAMD CO_2 Data	National CO_2 Emission Factors -Coal (0.103 tons/mmbtu) -Gas (0.058 tons/mmbtu) -Oil (0.087 tons/mmbtu)
CO_2 Emissions, TPY Method 3	National CO_2 Emission Factors -Coal (0.103 tons/mmbtu) -Gas (0.058 tons/mmbtu) -Oil (0.087 tons/mmbtu)	National CO_2 Emission Factors -Coal (0.103 tons/mmbtu) -Gas (0.058 tons/mmbtu) -Oil (0.087 tons/mmbtu)	National CO_2 Emission Factors -Coal (0.103 tons/mmbtu) -Gas (0.058 tons/mmbtu) -Oil (0.087 tons/mmbtu)

Table 7: Summary of the Georgia CO_2 analysis for southeastern states.

State	Change from 2005 to 2011			Change from 2005 to 2018		
	Method 1	Method 2	Method 3	Method 1	Method 2	Method 3
AL	-7.7%	-7.7%	-8.7%	-10.6%	-11.1%	-11.3%
FL	-8.4%	-8.4%	-5.9%	-17.7%	-21.7%	-19.5%
GA	-17.6%	-17.6%	-17.9%	-12.7%	-13.1%	-13.3%
KY	0.7%	0.7%	0.0%	-18.5%	-17.5%	-18.2%
MS	-8.0%	-8.0%	-6.6%	6.2%	3.2%	4.5%
NC	-13.4%	-13.4%	-16.2%	-21.3%	-18.5%	-21.5%
SC	-7.4%	-7.4%	-7.8%	-28.4%	-27.3%	-28.3%
TN	-26.6%	-26.6%	-27.2%	-35.8%	-35.0%	-35.5%
VA	-24.2%	-24.2%	-28.4%	-30.9%	-13.6%	-24.5%
WV	-12.0%	-12.0%	-13.0%	-12.4%	-11.4%	-12.4%
SEMAP	**-11.3%**	**-11.3%**	**-12.0%**	**-17.9%**	**-17.4%**	**-18.2%**

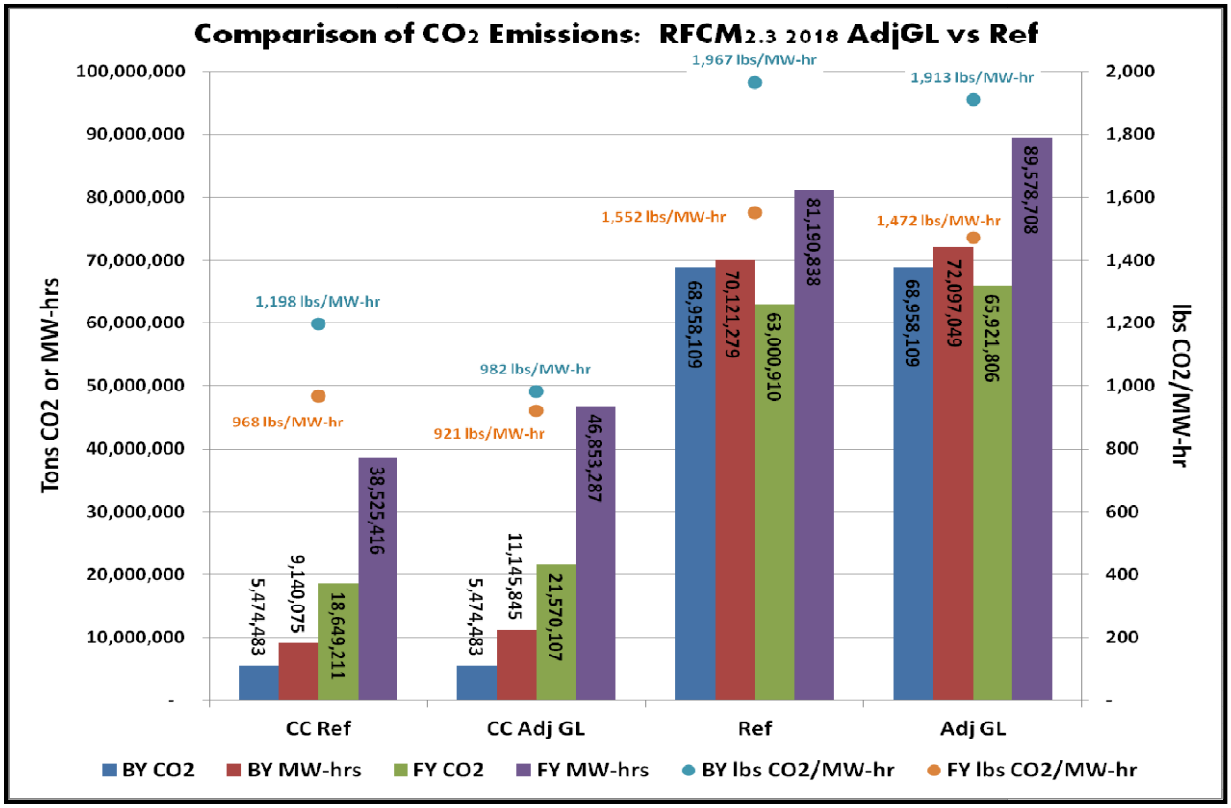
The study showed that for the southeastern United States, an 11% to 12% reduction in CO_2 emissions occurred between 2005 and 2011. The study also showed that a further 6% reduction is expected between 2011 and 2018. The different approaches to CO_2 emission calculations resulted in

slightly different emission reduction estimates from 2005 to 2018 over the entire region, ranging from 17.4% to 18.2%. These estimates do not reflect changes proposed in EPA's Clean Power Plan.[20]

Georgia's use of the ERTAC EGU tool projections to determine CO_2 emissions spurred interest by other states in the application of tool results for CO_2 emission estimation purposes. Virginia developed a post-processor written in Perl that users may apply to tool results. The post-processor provides a unit level summary for CO_2 evaluation. The CO_2 post-processor calculates unit-specific CO_2 emission factors in lbs/mmbtu and lbs/MWh for units reporting this data in the base year. The CO_2 post-processor provides fuel-based emission factors for existing units without base year CO_2 data and provides emission factors for new units that are compliant with the proposed New Source Performance Standard (NSPS) for power plants.

Figure 19 provides an example of how the CO_2 post-processor for the ERTAC EGU tool may be used in the analysis of input changes. In this graphic, the terms "CC Ref" and "Ref" refer to the 2018 results for the combined cycle sector in RFCM in the CONUS2.3 reference case and the 2018 results for all sectors in RFCM in the CONUS2.3 reference case, respectively. The term "CC Adj GL" refers to the 2018 results for the RFCM combined cycle sector in a tool run where the combined cycle units that underreported generation were updated. The term "Adj GL" refers to the 2018 results for all RFCM sectors in the tool run where the underreporting combined cycle units were updated. By summing the unit level results for 2018 in an Excel spreadsheet, the user may evaluate how updating the underreported gross load in the 2011 base year affected CO_2 emissions from RFCM combined cycle units as well as in RFCM overall. Such spreadsheets facilitate calculations of sector and region CO_2 rates in lbs/mmbtu or lbs/MWh, allowing users to evaluate the results of changes on metrics other than annual mass emission values. In this example, which used growth rates for RFCM based on AEO2014, updating the underreported combined cycle gross load resulted in an improvement in the overall RFCM system lbs/MWh metric of 80 lbs/MWh (1,552 lbs/MWh in the 2018 Ref case as compared to 1,472 lbs/MWh in the 2018 Adj GL case).

Figure 19: CO_2 evaluations for RFCM, combined cycle and all fuel/unit types.



ERTAC EGU WORKGROUP UPCOMING EFFORTS

The ERTAC EGU workgroup is leading or participating in a number of efforts regarding EGU projections. The workgroup's major current effort is the development of the CONUS2.4 reference run. The workgroup will base these runs on AEO2014 growth rates supplemented in certain regions by state-supplied information, unit-specific updates of the UAF as of March 30, 2015, and unit-specific updates of the controls file as of March 30, 2015. The CONUS2.4 results should be available for state review during the summer of 2015. At this time, the input files developed from comments supplied by stakeholders as of March 30, 2015 will be available for use by other tool users.

States within SRVC noted that utility estimates of growth as provided by information in IRPs deviated from the AEO2014 growth rates for the region. As a result, state staff within this region are evaluating the use of utility growth rates derived from IRPs and other publicly available sources for use in the CONUS2.4 effort.

The ERTAC EGU workgroup is also supporting efforts led by MARAMA to develop a regional air quality model for inclusion in the Baltimore 2008 ozone NAAQS moderate nonattainment area attainment plan. LADCO is using ERTAC EGU tool results in air quality modeling efforts designed to help evaluate transport strategies and compliance with the proposed 2015 ozone NAAQS. These efforts are relying on the ERTAC_to_SMOKE post-processor developed by the OTC. This post-processor allows users to convert ERTAC hourly output files to SMOKE-ready files for use in the Community Multi-Scale Air Quality Model (CMAQ), an atmospheric chemistry and transport model.

Regarding CO_2 EGU emissions estimates, Virginia staff is working on an upgrade to the CO_2 post-processor that will allow states to evaluate changes to the EGU emissions inventory resulting from increased future year utilization of combined cycle units. Virginia and Maryland staff are evaluating the use of the ERTAC EGU tool and the CO_2 post-processor in determining the effects of improved coal-fired unit efficiencies in future years.

The ERTAC EGU workgroup is evaluating options for obtaining funds to perform a tool function upgrade. This work includes prioritizing upgrades as well as determining which upgrades may be accomplished with available funding.

CONCLUSIONS

The ERTAC EGU tool has proven to be a useful projection tool for EGU activity and emissions. The input files reflect state-supplied information, which ensures that projections used in attainment and maintenance plans are conservative and appropriate for inclusion in SIPs. The tool supports the development of future air quality assessments in a manner that preserves the meteorological base year impacts, allowing HEDD and peak day analyses. Input and output data are transparent, which is helpful since SIP submittals must undergo public comment and EPA scrutiny. The ERTAC EGU tool is a low-cost approach to developing future year EGU emission projections suitable for use in SIP submittals.

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[1] Office of the Federal Register. "Implementation of the 2008 National Ambient Air Quality Standards for Ozone: State Implementation Plan Requirements; Final Rule" (Implementation Rule), 80 FR 12264. March 6, 2015. U.S. Environmental Protection Agency.

[2] Ibid., 80 FR 12268.

[3] Eyth, Alison. 2014. U. S. Environmental Protection Agency, NC, *personal communication.*

[4] Code of Federal Regulations. "Continuous Emission Monitoring," 40 CFR Part 75, 40 CFR Part 75.10(d)(1), U.S. Environmental Protection Agency.

[5] Air Quality Modeling Group, *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze*, U.S. Environmental Protection Agency Research Triangle Park, NC, April 2007; EPA-454/B-07-002, p. 82.

[6] 70 CFR Part 75, 40 CFR 75.19(c).

[7] Implementation Rule, 80 FR 12268, Footnote 16.

[8] Calcagni, John. *MEMORANDUM: Procedures for Processing Requests to Redesignate Areas to Attainment*, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 4, 1992, p. 9.

[9] Metropolitan Washington Council of Governments. *2002 Base Year Emissions Inventory Document for Washington, DC-MD-VA $PM_{2.5}$ Nonattainment Area*, March 7, 2008.

[10] Metropolitan Washington Council of Governments. "Appendix C: Point Source Inventories and Projections," *Plan to Improve Air Quality in the Washington, DC-MD-VA Region*, May 23, 2007.

[11] Code of Federal Regulations. "Requirements for Preparation, Adoption, and Submittal of Implementation Plans," 40 CFR Part 51 Subpart F, 40 CFR Part 51.102, U. S. Environmental Protection Agency.

[12] Code of Federal Regulations. "Provisions for Implementation of 8-Hour Ozone National Ambient Air Quality Standard," 40 CFR Part 51 Subpart X, 40 CFR 51.911(d), U.S. Environmental Protection Agency.

[13] Implementation Rule, 40 CFR 51.1110(b), 80 FR 12316.

[14] 40 CFR Part 75, Appendix A, 3.3.1 and 3.3.2.

[15] Code of Federal Regulations. "National Emission Standards for hazardous Air Pollutants: Coal-and Oil-Fired Electric Utility Steam Generating Units" (MATS), 40 CFR Part 63 Subpart UUUUU, U.S. Environmental Protection Agency, February 16, 2012, 77 FR 9304.

[16] Ibid., 40 CFR Part 63.9984(b).

[17] Ibid., 40 CFR Part 63 Subpart UUUUU, Table 2.

[18] Office of the Federal Register. "Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Proposed Rule", 80 FR 15354, U.S. Environmental Protection Agency, March 23, 2015.

[19] Clean Air Markets Division. *Part 75 Emissions Monitoring Policy Manual*, U.S. Environmental Protection Agency, Washington, D.C. 2013. p. 17-1.

[20] Kim, Byeong-Uk. "2018 CO_2 Emission Projections for the SESARM States," Presented at the fall meeting of the SESARM Air Directors, October 2013.