Description of 2010 and 2011 Data

The state-level CO_2 emission rates were estimated for 2010 and 2011 from unit-level emissions and generation data derived using the Emissions & Generation Resource Integrated Database (eGRID) methodology. eGRID is a comprehensive inventory of environmental attributes of the U.S. electric power system. The methodology used to produce eGRID integrates many different data sources on power plants and power companies, including, but not limited to: the Environmental Protection Agency (EPA), the Energy Information Administration (EIA), the North American Electric Reliability Corporation (NERC), and the Federal Energy Regulatory Commission (FERC). The majority of the emissions and generation unit-level data are from reports from units that submit data to the EPA under 40 CFR Part 75 and to the EIA on forms EIA-860 and EIA-923.

The unit-level emissions and generation data derived using the eGRID methodology are relied upon for determining the state-level CO_2 emission rates. One notable difference is that previously published editions of eGRID match emissions and generation at the plant level, while the development of the state-level data matches emissions and generation at the unit level in order to filter out units that are not likely subject to the Rule's applicability criteria. Also, the state-level data are limited to the following elements at the unit level: CO_2 emissions, nameplate capacity, net generation, state location, and information used to place the unit in each category.

Data are assembled at the unit level and are aggregated to the state-level generation totals, capacity totals, and emission rates for the categories listed in Table 1 below: Coal Steam (COALST), Oil Gas Steam (OGST), Natural Gas Combined Cycle (NGCC), Simple Cycle Combustion Turbines (SST), and Integrated Gasification Combined Cycle (IGCC).

In general, state-level calculations include units that are stationary combustion turbines, steam generating units or IGCCs that are: (1) capable of combusting more than 250 MMBtu/hr heat input of fossil fuel and (2) constructed for the purpose of supplying one-third or more of their potential net-electric output capacity and more than 219,000 MWh to any utility power distribution system for sale (that is, to the grid). In addition, for stationary combustion turbines to be included, the heat input must consist of over 90% natural gas. Industrial units that are not grid connected are excluded. Units for which fossil fuel is less than 10% of the heat input in a year are also excluded from the data in that year.

For units that report to the EPA under 40 CFR Part 75, reported CO_2 emissions are used. These emissions are either determined from continuous emissions monitors that measure CO_2 concentration and stack gas volumetric flow or, for units that combust certain gaseous and liquid fuels, fuel flow meters and fuel testing as required under appendix D and E of 40 CFR Part 75.

For units that do not report to the EPA under 40 CFR Part 75, CO_2 emissions are calculated from fuel use reported in the EIA-923 and emission factors under EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks or The Climate Registry Default Emission Factors. If no unit level fuel use exists in the EIA-923 dataset and prime mover fuel data exists, and there is more than one unit at a plant that has the same prime mover (e.g. steam turbine, combustion turbine, etc.), then prime mover fuel level emissions are distributed to each generator in the prime mover proportionately by nameplate capacity. For most cases (where all units in the prime mover would likely be covered by the rule), this apportionment does not matter because emissions are summed to the state level. However, if there is a unit in the prime mover that would not likely be covered by the rule, then this apportionment may not exactly match the amount of fuel actually burned and the associated emissions for each unit. Fuels categorized as “other” that could not be defined and assigned an emissions factor are excluded.

Net generation is taken from EIA-923 data. If no unit-level net generation exists in the EIA-923 dataset and prime mover fuel data exists, and there are more than one unit at a plant that have the same prime mover (e.g. steam turbine, combustion turbine, etc.), then prime mover fuel level net generation is distributed to each generator in the prime mover proportionally by nameplate capacity.

Table 1. Logic for determination of source CATEGORY

CATEGORY	**Category Name**	**Includes**
COALST	Coal Steam	Coal is designated as primary fuel. Nameplate capacity 25 MW or greater or if heat input capacity is 250MMBtu/hr or greater
OGST	Oil Gas Steam	All steam units not in “Coal Steam” category that have oil or gas primary fuel. Nameplate capacity 25 MW or greater.
NGCC	Natural Gas Combined Cycle Units - Duct burners and heat recovery steam generators are included with combustion turbines that are 25 MW.	NG is primary fuel or if actual fuel use is >90% NG. Combustion turbine parts having nameplate capacity 25 MW or greater. Any associated duct burners and heat recovery steam generators are included.
SST	Simple Cycle Combustion Turbines – 25 MW	Nameplate capacity 25 MW or greater & 33% capacity factor & 219,000MWh
IGCC	IGCC	IGCCs at: Wabash, Polk, Edwardsport