report aggregated results for "model" plants (i.e., aggregates of generating units with similar operating characteristics). Parsed files approximate the IPM results at the generating unit level. This document defines the column headers found in EPA v.5.14 parsed files.

“Parsed” data, representing model projections disaggregated to the unit level, will often differ from the corresponding variables (e.g., pollutant emission rates) reported for each unit in the NEEDS database, because the model may select different fuels, add new pollution control technologies, or revise the operation of particular units in response to future economic and regulatory conditions. (EPA uses detailed information about rail and barge links for coal, and pipeline availability for natural gas to constrain the model’s choices of available fuels at each unit (see IPM Documentation, Chapters 9 and 10 http://www.epa.gov/powersectormodeling/)

EPA’s application of IPM can result in differences between historic (observed) and future (simulated) values for the following parameters affecting EGU emissions:

- Post-combustion pollution control technologies installed (for SO2, NOX, HCl, Hg, PM, and CO2)
- Combustion control technologies installed (for NOX)
- Fuel type(s) combusted
- Generation produced
- Heat rate (the model may only change a unit’s heat rate if the heat rate improvement retrofit option is made available in that analysis)

Some apparent differences in input (NEEDS) and output (parsed) data are related to EPA’s approach to using each type of input data in the modeling process. For example, while NEEDS reports unit-level SO2 permit rates (where known), EPA uses that input parameter as an upper-bound constraint to prevent the model from making decisions that would exceed that emission rate. However, the model may select combinations of fuels and pollution control technologies that result in projected SO2 emission rates that are lower than the indicated SO2 permit rates for the unit in question. This approach preserves the model’s flexibility to select the most economic type of coal available for each unit based on the fuel’s simulated market price, sulfur content, and the environmental regulations applicable to the unit. The model’s decisions on fuel selection and pollution control configuration for each unit can be reviewed in the parsed file; the associated emission rate for the unit can be calculated by dividing the emission mass by the heat input in the parsed file.

For example, at the Seminole plant in Florida, unit 1 (Unique ID: 136_B_1) has a SO2 permit rate of 0.67 lbs/mmBtu in NEEDS. The annual SO2 rate projected by the model can be calculated by dividing the annual SO2 emissions by the heat input, both in the parsed file. This results in a projected 2018 SO2 emission rate of 0.22 lbs/mmBtu, which is lower than the permit rate listed in NEEDS.

One may also compare the IPM-projected 0.22 lbs/mmBtu SO2 emission rate to the actual 2011 SO2 emission rate of 0.35 lbs/mmBtu (calculated from Air Markets Program Data (AMPD), http://ampd.epa.gov/ampd/). Each of the potential drivers of this difference in historic and projected emission rates at this unit can be considered by reviewing the relevant modeling inputs and outputs. First, a comparison of the unit’s pollution control technologies present in 2011 and those shown in the 2018 modeling outputs reveals that the model did not apply any new pollution control technology to this unit (EIA Form 860 for year 2011, http://www.eia.gov/electricity/data/eia860/). Second, the removal efficiency of the FGD at the unit from reported data in 2011 was 92.3% (EIA Form 923 for year 2011, http://www.eia.gov/electricity/data/eia923/), while NEEDS shows a 95% removal efficiency assumed in IPM modeling for the FGD on this unit (as explained in Section 5.1 of the IPM Documentation (page 5-2), for power sector modeling purposes, EPA assumes that FGD SO2 removal efficiencies are equivalent to the values reported for each FGD on EIA form 860). Recalculating the 2018 projected emissions at this unit, assuming the 92.3% removal efficiency reported for the unit’s FGD in 2011, would yield an emission rate equivalent to the 0.35 lbs/mmBtu reported in 2011. This difference in the reported 2011 SO2 removal efficiency and the SO2 removal efficiency assumed for power sector modeling explains the difference in reported 2011 and projected 2018 SO2 emission rates at this unit. If differences between historic values and assumed or projected future-year values in observed unit characteristics such as removal efficiency, heat rate, or retrofitted controls do not explain differences in historic and projected emission rates, then by process of elimination such a difference in emission rates would be due to differences in historic and modeled future-year fuel choices.

Unlike for SO2, where the model is determining future emission rates based on a suite of fuel and pollution control technology choices that are available inside the model, EPA’s methodology for making EGU NOX projections is based on an interpretation of each unit’s historical NOX emission rate data combined with potential pollution control configurations. From this data analysis, EPA quantifies four potential future NOX emission rates for each unit, from which the model selects one future NOX rate depending on the conditions represented in the future-year scenario for each analysis. These four potential NOX rates for each unit are listed in NEEDS and are derived from unit-specific reported emission data combined with assumptions about pollution control technology performance, as described in Attachment 3-1 and Figure 3-4 in the IPM Documentation, available at www.epa.gov/powersectormodeling. As explained in the modeling documentation, the projected NOx rate for a given unit (reported in the parsed file for a given IPM analysis) will either be one of the four potential NOx rates shown for that unit in the corresponding input file (NEEDS), or it may be a yet lower emission rate if the model chose to add a new post-combustion control technology to that unit (which will also be indicated in the parsed file).

Field Name	Column	Unit of Measure	Definition	**Key to Recurring Column Values**
UniqueID	A	-------	The unique identifier assigned to a boiler or generator within a plant. It consists of the Plant ID (or ORIS Code), an indication of whether the unit is a boiler ("B"), generator ("G"), or committed unit ("C"), and the Unit ID. For example, for the Unique ID "113_B_1", "113" is the Plant ID, "B" indicates that this unit is a boiler, and "1" indicates that the ID of the boiler is 1.	-------
RegionName	B	-------	The electricity grid region the unit is located in.	-------
StateName	C	-------	These four fields identify the geographic location of the unit. The State Code is the FIPS State Code, and the County Code is the FIPS County Code. New units have blanks in these columns, while committed units have zeros. Federal information processing standards (FIPS) codes are a standardized set of numeric or alphabetic codes issued by the National Institute of Standards and Technology (NIST) to ensure uniform identification of geographic entities through all federal government agencies.	-------
StateCode	D	-------		-------
CountyName	E	-------		-------
CountyCode	F	-------		-------

ORISCode	G	-------	A unique identifier assigned to each power plant in NEEDS. While the ORIS code is unique for each plant, all generating units within a plant will typically have the same ORIS code. For committed units (i.e., those not currently operating, but firmly anticipated to be operational in the future), the entry in this field might be a dummy ORIS code assigned as a placeholder unique ID to the committed plant. (Note: ORIS originally referred to the Office of Regulatory Information Systems in the Department of Energy (DOE) Energy Information Administration (EIA) which was responsible for assigning unique identification codes to utility power plants.)	-------
UnitID	H	-------	The identifier assigned to each unit/boiler in a given plant.	-------
PlantName	I	-------	The plant's name.	-------
HeatRate	J	-------	The unit's heat rate.	-------
OnLineYear	K	-------	For existing units, this is the year the unit came on line. For committed units, this is the year the unit is projected to come on line	-------
RetirementYear	L	-------	The year a unit is planned to be retired. For units without a firm retirement year, this field has a value of 9999	-------
PlantType	M	-------	The type of electric generating unit, usually defined by the "prime mover" and/or fuels burned. "Prime mover" refers to the machine (e.g., engine, turbine, water wheel) that drives an electric generator or the device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).	Biomass
				Coal Steam
				Combined Cycle
				Combustion Turbine
				Fossil Waste
				Fuel Cell
				Geothermal
				Hydro
				IGCC
				Landfill Gas
				Municipal Solid Waste
				Non-Fossil Waste
				Nuclear
				O/G Steam
				Pumped Storage
				Solar
				Tires
				Wind
Firing	N	-------	This field, which applies only to boilers, indicates the burner type and configuration (e.g., cell, cyclone, FBC (fluidized bed combustion), stoker/SPR, tangential, or vertical). A blank appears in instances where the firing characteristics of a boiler are unknown or the unit is a not a boiler.	**Cell:** boilers that combine 2-3 standard burners into a compact, vertical assembly installed on the furnace wall; multiple cells utilized within a furnace.
				Cyclone: A special type of burner for coals with low fusion point ashes. Combustion occurs within the horizontal burner generating high temperatures which turn the ash into molten slag. The term "wet bottom" furnace often accompanies the cyclone burner.
				FBC: "fluidized bed combustion" where solid fuels are suspended on upward-blowing jets of air, resulting in a turbulent mixing of gas and solids and a tumbling action which provides especially effective chemical reactions and heat transfer during the combustion process.
				Stoker/SPR: stoker boilers where lump coal is fed continuously onto a moving grate or chain which moves the coal into the combustion zone in which air is drawn through the grate and ignition takes place. The carbon gradually burns off, leaving ash which drops off at the end into a receptacle, from which it is removed for disposal.
				Tangential (also referred to as "corner firing"): burners located along furnace corners in multiples of 4. Burner angle is off-set working in conjunction with the opposing corner burner to create a vertical, circular swirling combustion zone within the furnace.
				Turbo (wall fired burner): Burner design for pet coke and low volatile bituminous coals (Riley trademark name: "Turbo Furnace"). Hour glass shaped furnace with rectangular shaped burners angled downwards.
				Vertical: standard furnace (assume wall fired)
				Wall: standard burner / furnace design used today. Circular burners located on the front and rear furnace walls at multiple elevations.

Bottom	O	-------	This field, which applies only to boilers, indicates whether the bottom of the combustion chamber is "wet" (i.e., ash is removed from the furnace in a molten state) or "dry" (i.e., the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid). A blank appears in instances where the bottom characteristics of a boiler were not known or the unit was not a boiler.	Dry	
				Wet	
EMFControls	P	-------	This field shows the combination of SO2 scrubbers, NOx post-combustion controls, and particulate matter controls that already exist at a unit. The entries in this column are compiled from the "NOx Post-CombControl," "Wet/DryScrubber" and "Particulate Matter Type" fields. Together with the entry in the "Firing" and "Modeled Fuels" fields, the entries in this field are used for the assignment of the Emission Modification Factors (EMFs) for mercury. The EMFs enable the model to capture mercury emission reductions that are a function of the rank of coal burned (bituminous, subbituminous and lignite), the specific burner type, and the configuration of SO2, NOx, and particulate matter control devices. Consolidating the controls that impact mercury reductions into this field helps to insure that the correct EMFs are assigned to each unit. Note that EMFs are metric of the extent of mercury emission reduction achieved by these non-mercury controls, and do not include the presence or impact of mercury-specific controls (e.g., ACI).	-------	
NOxControl	Q	-------	This field indicates the NOx combustion controls which are in existence at a generating unit after the model is run. Combustion controls reduce NOx emissions during the combustion process generally by regulating flame characteristics such as temperature and fuel-air mixing.	AA	Advanced Overfire Air
				BF	Biased Firing (alternate burners)
				BOOS	Burners-Out-Of-Service
				CM	Combustion Modification/Fuel Reburning
				CO	Combustion Optimization
				DLNB	Dry Low NOx Burners
				FR	Flue Gas Recirculation
				FU	Fuel Reburning
				H2O	Water Injection
				LA	Low Excess Air
				LN	Low NOx Burner
				LNB	Bottom only)
				LNBO	Low NOx Burner Technology w/ Overfire Air
				LNC1	coupled OFA
				LNC2	Separated OFA
				LNC3	coupled/Separated OFA
				LNCB	Low NOx Cell Burner
				LNF	Low NOx Furnace
				MR	Methane Reburn
				N2	Nitrogen
				NDI	Nitrogen Diluent Injection
				NGR	Natural Gas Reburn
				NH3	Ammonia Injection
				OFA	Overfire Air
				other	Other
				ROFA	Rotating Overfire Air
				SC	Slagging
				SOFA	Stationary Overfire Air
				STC	Staged Combustion
				STM	Steam Injection
				WIR	Underfire Air
SO2Control	R	-------	This field indicates the SO2 controls which are in existence at a generating unit before the model is run. SO2 controls reduce SO2 emissions by using chemical processes to remove SO2 from the post-combustion emission stream.	Dry Scrubber	
				Wet Scrubber	
				Reagent Injection	
FossilUnit	S	-------	Indicates whether a unit is fossil-fuel fired	Fossil	
				Non-Fossil	
BGCI	T	-------	Indicates where a unit is an existin boiler, and existing generator, or a committed unit that is not currently in operation	B - Boiler	
				G - Generator	
				C - Committed	
Year	U	-------	The model run year from which the parsed results were derived.	-------	

FuelType	V	-------	This field indicates the type of fuel used by the unit.	Biomass
				Coal
				Fwaste
				Geothermal
				Hydro
				LF Gas
				MSW
				NaturalGas
				Non-Fossil
				Nuclear
				Oil
				Pet. Coke
				Solar
				Waste Coal
				Wind
RetrofitSO2NOxControls	W	-------	Summarizes all of the control technologies that a unit has put on. The retrofits are cumulative to the year for which the run is parsed. For instance, if the parsed file is for 2020, it will include all retrofits projected by the model for the unit through 2020.	CC Early Retirement
				Coal Early Retirement
				CT Early Retirement
				Mercury Control
				Mercury Control / Coal Early Retirement
				O/G Early Retirement
				SCR
				SCR - O/G Steam
				Scrubber
				Scrubber / Mercury Control
				Scrubber / SCR
				Scrubber / SNCR
				SNCR
FuelUseWinter	X	TBtu	Projected fuel consumed (TBtu) at the unit in January - April and October - December during the year for which the run was parsed.	-------
FuelUseSummer	Y	TBtu	Projected fuel consumed (TBtu) at the unit in May - September during the year for which the run was parsed.	-------
FuelUseTotal	Z	TBtu	Projected fuel consumed (TBtu) at the unit during the year for which the run was parsed.	-------
BITFuelUseWinter	AA	TBtu	These nine columns give the projected coal consumption (TBtu), by coal rank, during the summer months (May - September), winter months (January - April and October - December), and the entire year for which the run was parsed.	-------
BITFuelUseSummer	AB	TBtu		-------
BITFuelUseTotal	AC	TBtu		-------
SUBFuelWinter	AD	TBtu		-------
SUBFuelSummer	AE	TBtu		-------
SUBFuelTotal	AF	TBtu		-------
LIGFuelWinter	AG	TBtu		-------
LIGFuelSummer	AH	TBtu		-------
LIGFuelTotal	AI	TBtu		-------
GWhWinter	AJ	GWh	Projected generation (GWh) produced by the unit in January - April and October - December during the year for which the run was parsed.	-------
GWhSummer	AK	GWh	Projected generation (GWh) produced by the unit in May - September during the year for which the run was parsed.	-------
GWhTotal	AL	GWh	Projected generation (GWh) produced by the unit during the year for which the run was parsed.	-------
CO2Winter	AM	Mtons (thousands short tons)	Projected winter (January - April and October - December) CO_2 emissions (MTons) during the year for which the run was parsed.	-------
CO2Summer	AN	Mtons (thousands short tons)	Projected summer (May - September) CO_2 emissions (MTons) during the year for which the run was parsed.	-------
CO2Total	AO	Mtons (thousands short tons)	Projected annual CO_2 emissions (MTons) during the year for which the run was parsed.	-------
CO2Winter (Metric)	AP	Mtons (thousands metric tons)	Projected winter (January - April and October - December) CO_2 emissions MTons (Thousand of Metric Tons) during the year for which the run was parsed.	-------
CO2Summer (Metric)	AQ	Mtons (thousands metric tons)	Projected summer (May - September) CO_2 emissions MTons (Thousand of Metric Tons) during the year for which the run was parsed.	-------
CO2Total (Metric)	AR	Mtons (thousands metric tons)	Projected annual CO_2 emissions MTons (Thousand of Metric Tons) during the year for which the run was parsed.	-------

MERWinter	AS	Tons (short tons)	Projected winter (January - April and October - December) mercury emissions (MTons) during the year for which the run was parsed.	-------
MERSummer	AT	Tons (short tons)	Projected summer (May - September) mercury emissions (MTons) during the year for which the run was parsed.	-------
MERTotal	AU	Tons (short tons)	Projected annual mercury emissions (MTons) during the year for which the run was parsed.	-------
NOXWinter	AV	Mtons (thousands short tons)	Projected winter (January - April and October - December) NOx emissions (MTons) during the year for which the run was parsed.	-------
NOXSummer	AW	Mtons (thousands short tons)	Projected summer (May - September) NOx emissions (MTons) during the year for which the run was parsed.	-------
NOXTotal	AX	Mtons (thousands short tons)	Projected annual NOx emissions (MTons) during the year for which the run was parsed.	-------
SO2Winter	AY	Mtons (thousands short tons)	Projected winter (January - April and October - December) SO2 emissions (MTons) during the year for which the run was parsed.	-------
SO2Summer	AZ	Mtons (thousands short tons)	Projected summer (May - September) SO2 emissions (MTons) during the year for which the run was parsed.	-------
SO2Total	BA	Mtons (thousands short tons)	Projected annual SO2 emissions (MTons) during the year for which the run was parsed.	-------
HCLWinter	BB	Mtons (thousands short tons)	Projected winter (January - April and October - December) HCl emissions (MTons) during the year for which the run was parsed.	-------
HCLSummer	BC	Mtons (thousands short tons)	Projected summer (May - September) HCl emissions (MTons) during the year for which the run was parsed.	-------
HCLTotal	BD	Mtons (thousands short tons)	Projected annual HCl emissions (MTons) during the year for which the run was parsed.	-------
ASHWinter	BE	Mtons (thousands short tons)	Projected winter (January - April and October - December) ash (MTons) during the year for which the run was parsed.	-------
ASHSummer	BF	Mtons (thousands short tons)	Projected summer (May - September) ash (MTons) during the year for which the run was parsed.	-------
ASHTotal	BG	Mtons (thousands short tons)	Projected annual ash (MTons) during the year for which the run was parsed.	-------
FOMCost	BH	Million US$ / yr	Fixed operation and mainetenance (O&M) cost for the unit during the year for which the run was parsed	-------
VOMCostWinter	BI	Million US$ / yr	Variable operation and maintenance (O&M) cost for the unit for the winter months (January - April and October - December) during the year for which the run was parsed	-------
VOMCostSummer	BJ	Million US$ / yr	Variable operation and maintenance (O&M) cost for the unit for the summer months (May - September) during the year for which the run was parsed	-------
VOMCostTotal	BK	Million US$ / yr	Variable operation and maintenance (O&M) cost for the unit during the year for which the run was parsed	-------
FuelCostWinter	BL	Million US$ / yr	Fuel cost for the unit for the winter months (January - April and October - December) during the year for which the run was parsed	-------
FuelCostSummer	BM	Million US$ / yr	Fuel cost for the unit for the summer months (May - September) during the year for which the run was parsed	-------
FuelCostTotal	BN	Million US$ / yr	Fuel cost for the unit during the year for which the run was parsed	-------
CapitalCost	BO	Million US$ /yr	Annualized capital cost expenditures (i.e. added controls and upgrades) for the unit during the year for which the run was parsed	-------
Capacity	BP	MW	The net summer dependable capacity (in megawatts) of the unit available for generation for sale to the grid. Net summer dependable capacity is the maximum capacity that the unit can sustain over the summer peak demand period reduced by the capacity required for station services or auxiliary equipment.	-------
Post Combustion Control and Heat Rate I	BQ	-------	Summary of the SO_2, NO_X, and Mercury post-combustion controls installed at the unit during the run year, as well as any heat rate improvements made to the unit	-------
Post Combustion Control (Scrubber: Wet	BR	-------	Indicates if the unit has a Wet or Dry Scrubber.	-------
Baghouse Retrofit (in conjunction with either dry FGD, ACI+Toxecon, and/or DSI)	BS	-------	For some plant configurations, a baghouse is required for some retrofits (deals with meeting PM standard as cobenefit, so other PM controls not needed)	ACI with Toxecon Dry Scrubber Dry Scrubber / ACI with Toxecon Dry Scrubber / DSI DSI