Guide to NEEDS[1]

Plant Name: The plant's name.

Unique ID: 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 unit ID of the boiler is 1.

ORIS Code: 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.)

Boiler/Generator/Committed Unit: An indicator of whether the unit is a boiler ("B"), generator ("G"), or committed unit ("C").

Unit ID: The identifier assigned to each unit/boiler in a given plant.

CAMD Database Unit ID: Unit level identifier assigned by EPA's Clean Air Markets Division (CAMD) business system. Unlike other identification codes (e.g., ORIS codes), which are subject to change, once assigned to a unit, the CAMD Database Unit ID is not changed.

PlantType: 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)). Table 1 lists and describes the Plant Types appearing in NEEDS, v.3.1.

Table 1. Plant Types in NEEDS, v.3.1

PlantType	Description
Biomass	Any generating unit whose primary fuel is biomass.
Coal Steam	A plant in which the prime mover is a steam turbine, where the steam used to drive the turbine is produced in a boiler burning coal.
Combined Cycle	An electric generating technology in which electricity is produced both from the primary combustion turbine(s) and from otherwise lost heated exhaust gases which drive a secondary steam turbine.
Combustion Turbine	A plant in which the prime mover is a natural gas or oil-fired turbine.
FBC	A plant in which the prime mover is a steam turbine, where the steam used to drive the turbine is obtained by Fluidized Bed Combustion which involves the combustion of fuel mixed with a bed of inert material, such as limestone or dolomite, held in a fluid like state by the means of air or other gases being passed through the materials.
Fossil Waste	Any generating unit whose primary fuel is a waste product of petroleum or natural gas. This includes blast furnace and coke over gas. It does not include petroleum coke or waste coal which are specified

[1]NEEDS refers to the National Electric Energy Data System, a database of all existing and planned-committed electric generating units. Planned-committed units are new electric generating facilities that are not currently operating but that have initiated construction or obtained financing.

	separately among the “Modeled Fuels” (column AL) in NEEDS
Geothermal	A plant in which the prime mover is a steam turbine, where the steam is obtained directly or indirectly from heat found in geological formations.
Hydro	A plant in which the turbine generators are driven by falling water.
IGCC	Integrated gasification combined cycle is a combined cycle plant whose primary fuel is synthesis gas produced by a co-located coal gasification facility.
Landfill Gas	Any generating unit whose primary fuel is landfill gas.
Municipal Solid Waste	Any generating unit whose primary fuel is municipal solid waste.
Non-Fossil Waste	Any generating units whose primary fuel is a non-fossil waste product that does not itself qualify as biomass. This includes waste products of liquid and gaseous renewable fuels (e.g., red and black liquor from pulping processes, digester gases from waste water treatment). It does not include urban wood waste which is included in biomass.
Nuclear	A plant in which the prime mover is a steam turbine, where the steam is produced by the heat derived from the fission of nuclear fuel in a reactor.
O/G Steam	A plant in which the prime mover is a steam turbine, where the steam used to drive the turbine is produced in a boiler burning fuel oil or natural gas.
Pumped Storage	A hydroelectric plant that releases water previously pumped into an elevated storage reservoir (usually during off-peak periods) to drive turbine generators (usually during peak periods) located in a power plant at a lower level.
Solar	Solar photovoltaic or thermal technology used to generate electricity.
Tires	Any generating unit whose primary fuel is tires or a tire-derived fuel.
Wind	A plant in which the prime mover is a turbine driven by wind power.

Region Name: The region, used in the Integrated Planning Model (IPM), where the generating unit is located. The IPM regions cover the lower 48 U.S. states and the District of Columbia. The regions are defined to enable IPM to accurately represent the operation and structure of U.S. electric power system. IPM regions are generally subdivisions of the 10 North American Electric Reliability Council (NERC) regions and aggregations of the U.S. electricity grid's contiguous control areas. Figure 1 provides a map of the IPM regions. Table 2 gives the full name of each region and its relation the 11 NERC regions. (Note: This field will be left blank in NEEDS, v.3.1 and Figure 1 and Table 2 will not be provided until the assumptions for EPA Base Case, v.3.1 are finalized. Thirty-two (32) U.S. IPM regions are anticipated.)

State Name: The state where the unit is located.

State Code: This field contains the FIPS State Code. Federal information processing standards codes (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.

County: The county where a unit is located. Along with the State Name, it identifies the geographic location of the unit.

County Code: This field contains the FIPS County Code.

Capacity 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.

Heat Rate: The net heat input (in Btu) required to generate 1 kilowatt hour of electricity.

On Line Year: The year in which the unit is commissioned.

Retirement Year: The year in which the unit is to be decommissioned. ("9999" indicates that the unit has not been retired.)

SO2 Permit Rate: The SO2 emission rate (in lb/mmBtu) limit that applies to the unit due to federal, state or local emission regulations.

Firing: 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 were not known or the unit was a not a boiler.

Bottom: 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.

Cogen: This field indicates whether a unit is a cogenerator (Y = yes; N = no.). A unit is considered a cogenerator if it produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes.

NOxControl: This field indicates the NOx combustion controls employed by a generating unit. Combustion controls reduce NOx emissions during the combustion process generally by regulating flame characteristics such as temperature and fuel-air mixing. Table 3 lists the different types of NOx combustion controls that appear in this field.

Table 3. Key to Entries Appearing in "NOxControl" field in NEEDS, v.3.1

Control Code	Control Description
AA	Advanced Overfire Air
BF	Biased Firing (alternate burners)
BOOS	Burners-Out-Of-Service
CM	Combustion Modification/Fuel Reburning
Combustion Control	Combustion Control
Combustion Optimization	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	Low NOx Burner Technology (Dry Bottom only)
LNBO	Low NOx Burner Technology w/ Overfire Air
LNC1	Low NOx Burner Technology w/ Closed-coupled OFA
LNC2	Low NOx Burner Technology w/ Separated OFA
LNC3	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
LNCB	Low NOx Cell Burner

Low NOx Burner	Low NOx Burner
Low NOx furnace	Low NOx furnace
NH3	Ammonia Injection
OFA	Overfire Air
OV	Overfire Air
Overfire Air	Overfire Air
ROFA	Rotating Overfire Air
SC	Slagging
SOFA	Stationary Overfire Air
STAGED COMBUSTION	Staged Combustion
STM	Steam Injection

Post-CombControl: This column indicates the post-combustion NOx emission controls at a generating unit. There are two NOx post-combustion control options: Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR). Post-combustion controls operate downstream of the combustion process and remove NOx emissions from the flue gas.

Wet/DryScrubber: This field indicates if a unit has an SO2 scrubber, and, if so, whether it is a wet or dry scrubber. Also known as flue gas desulfurization (FGD) systems, SO2 scrubbers use chemical and physical absorption to remove SO2 from the flue gas. Wet scrubbers use a liquid sorbent to remove SO2 and the flue gas leaving the absorber is moisture saturated. With dry scrubbers the flue gas leaving the absorber is not saturated. For circulating fluidized bed units (as shown in the "Plant Type" field), this field indicates whether reagent injection is used for SO2 control. Reagent injection involves adding finely crushed limestone to the fluidized bed. During combustion, the limestone is reduced to lime, the sulfur in the fuel is oxidized to form SO2, and, in the presence of excess oxygen, the SO2 reacts with the lime particles to form calcium sulfate, which can be removed with the bottom ash or collected with the fly ash by a downstream particulate matter (PM) control device.

Particulate Matter Type: This field indicates whether a generating unit has any of the following particulate matter (PM) controls: baghouse (B), cyclone (C), electrostatic precipitator (ESP), hot side electrostatic precipitator with flue gas conditioning (ESPH), cold side electrostatic precipitator with flue gas conditioning (ESPC), and wet scrubber (WS).

EMF_Controls: 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 "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 as shown in the six subsequent "Controlled Hg EMF" and "Uncontrolled Hg EMF" fields. 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.

Dedicated Hg Controls: This field indicates whether the generating unit uses activated carbon injection (ACI) for mercury emission control.

A note on the next four fields: During model set-up, generating units are assigned starting summer and winter NOx rates. The rates assigned depend on the unit's current combustion and post-combustion NOx controls and whether the unit is subject to NOx limits (summer or annual). The first two of the following four fields contain the NOx base rates, i.e., those applicable for the unit under existing NOx limits. The subsequent two fields contain the NOx rates that may be

applicable for the unit if a future policy model run includes NOx limits beyond those reflected in the baseline emission rate data.

Uncontrolled NOx Base Rate: This rate reflects that the existing NOx combustion controls are operating and existing NOx post combustion controls (SCR, SNCR) are not operating.

Controlled NOx Base Rate: This rate reflects that the existing NOx combustion controls and existing NOx post combustion controls (SCR, SNCR) are operating. Note: If the unit does not have existing post-combustion NOx controls, its NOx emission rate will only reflect the rate associated with combustion controls, and the emission rate value in this field will be the same as in the previous field.

Uncontrolled NOx Policy Rate: This rate reflects that state-of-the-art NOx combustion controls are installed and operating and existing NOx post combustion controls (SCR, SNCR) are not operating.

Controlled NOx Policy Rate: This rate reflects that state-of-the-art NOx combustion controls are installed and operating and existing NOx post combustion controls (SCR, SNCR) are operating. Note: If the unit does not have existing post-combustion NOx controls, its NOx emission rate will only reflect the rate associated with combustion controls, and the emission rate value in this field will be the same as in the previous field.

Controlled Hg EMF for BIT: Mercury Emission Modification Factor (EMF) when the unit combusts bituminous coal and existing NOx post combustion controls (SCR or SNCR) are operating. "Mercury EMF" is defined as the percentage of fuel mercury left after accounting for the mercury removal obtained by the SO2, NOx, and particulate controls shown in the "EMF_Controls" field.

Controlled Hg EMF for Subbit: Mercury Emission Modification Factor (EMF) when the unit combusts subbituminous coal and existing NOx post combustion controls (SCR or SNCR) are operating.

Controlled Hg EMF for LIG: Mercury Emission Modification Factor (EMF) when the unit combusts lignite coal and existing NOx post combustion controls (SCR or SNCR) are operating.

Uncontrolled Hg EMF for BIT: Mercury Emission Modification Factor (EMF) when the unit combusts bituminous coal and existing NOx post combustion controls (SCR or SNCR) are not operating.

Uncontrolled Hg EMF for Subbit: Mercury Emission Modification Factor (EMF) when the unit combusts subbituminous coal and existing NOx post combustion controls (SCR or SNCR) are not operating.

Uncontrolled Hg EMF for LIG: Mercury Emission Modification Factor (EMF) when the unit combusts lignite\ coal and existing NOx post combustion controls (SCR or SNCR) are not operating.

Scrubber Efficiency %: The removal efficiency of the SO2 scrubber.

Modeled Fuels: This field indicates the fuels that can be combusted by the unit. The available fuel choices are listed in Table 4.

Table 4. Modeled Fuels in NEEDS, v.3.1

Biomass
Bituminous Coal

Distillate Fuel Oil
Fossil Waste
Geothermal
Hydro
Landfill Gas
Lignite Coal
Municipal Solid Waste (MSW)
Natural Gas
Non-Fossil Waste
Nuclear Fuel
Petroleum Coke
Pumped Storage
Residual Fuel Oil
Solar
Subbituminous Coal
Tires
Waste Coal
Wind