U.S. Department of Energy Energy Information Administration Form EIA-767 (2005)	***STEAM-ELECTRIC PLANT OPERATION AND DESIGN REPORT***	Form Approved OMB No. 1905-0129 Approval Expires: 11/30/2007

PURPOSE

Form EIA-767 collects information annually from all U.S. plants with a total existing or planned organic-fueled or combustible renewable steam-electric unit that has a generator nameplate rating of 10 megawatts or larger. This report is used for economic analyses conducted by the Department of Energy. The data from this form appear in the *Electric Power Annual* and the *Annual Energy Review.* The data collected on this form are used to monitor the current status and trends in the electric power industry and to evaluate the future of the industry.

REQUIRED RESPONDENTS

A Form EIA-767 must be completed and filed for each existing, under-construction, or planned U.S. organic-fueled or combustible renewable steam-electric generating plant with a nameplate capacity of 10 or more megawatts regardless of current ownership and/or operation.

- If plant has a nameplate capacity of 100 megawatts or greater, complete the entire Form EIA-767.
- If plant has a nameplate capacity of at least 10 megawatts but less than 100 megawatts, complete Schedules 1, 2, 4 (Part A, D, and E), 5, 7 and 8 (Part A and B). Schedule 10, "Footnotes," is required when applicable.

RESPONSE DUE DATE

No later than April 30 following the close of the reporting year.

METHODS OF FILING RESPONSE

Submit your data electronically using EIA's secure Internet Data Collection system (IDC). This system uses security protocols to protect information against unauthorized access during transmission.

- If you have not registered with EIA's Single Sign-On system, send an e-mail requesting assistance to: eia-767@eia.doe.gov.
- If you have registered with Single Sign-On, log on at https://signon.eia.doe.gov/ssoserver/login.
- If you are having a technical problem with logging onto the IDC or using the IDC, contact the IDC Help Desk for further information at:

E-Mail: CNEAFhelpcenter@eia.doe.gov.

Phone: 202-287-1333

- If you need an alternate means of filing your response, contact the Help Desk.

Retain a completed copy of this form for your files.

CONTACTS

Internet System Questions: For questions related to the Internet Data Collection system, see the help contact information immediately above.

Data Questions: For questions about the data requested on Form EIA-767, contact:

Natalie Ko
Telephone Number: (202) 287-1957
FAX Number: (202) 287-1959
E-mail: eia-767@eia.doe.gov.

GENERAL INSTRUCTIONS

1. Operators of plants in the United States, whether existing, under-construction, or planned should complete the parts of the form where applicable based on the following criteria:

PLANT TYPE	PLANT CAPACITY	REQUIRED SCHEDULES	BURDEN (HOURS)
Organic-fueled or combustible renewable steam-electric	100 megawatts or greater	All Schedules	66.3
Organic-fueled or combustible renewable steam-electric	10 to less than 100 megawatts	Schedules 1, 2, 4 (Part A, D, and E), 5, 7, and 8 (Part A and B)	3.4

2. Verify all preprinted information. If incorrect, revise the incorrect entry and provide the correct information. In addition, provide an explanation for any changes to pre-printed data in the Schedule 10. Provide any missing information.

3. Complete applicable schedules for organic fuels, depending on capacity. For determining plant capacity, include waste-heat units with auxiliary firing. Do not include waste-heat units without auxiliary firing or auxiliary, house, or startup boilers. A separate Form EIA-767 must be submitted for each qualifying plant. Planned equipment is defined, for reporting purposes, as equipment that is on order and expected to go into commercial service within 5 years.

4. If a report is to be submitted for a plant that has not been assigned an EIA utility-plant code, call the EIA contact identified on page i of the instructions.

5. The form is designed for reporting at two levels: Schedules 2 and 3 request information at the plant level. Schedules 4 through 9 request information at the equipment level (i.e., generator, boiler, flue gas particulate collector, etc.).

6. Schedule 10 is for footnotes. Footnotes must be provided where instructed, or when additional explanation is requested. Information reported on this form that is inconsistent with other information filed with EIA should be explained in a footnote.

7. If the information provided is correct indicate in the box, “CHECK IF PRE-PRINTED DATA ARE CORRECT” at the bottom of the page. If the entire page is not applicable, then indicate in the box “CHECK IF PAGE NOT APPLICABLE” at the bottom of the page.

8. Information provided on this form should be for the calendar year indicated in the upper left-hand corner of each page of the form. Design information should be current as of December 31st of the reporting year.

9. Information provided should be actual data to the extent possible. If actual data are not available, enter estimated values. Do not put an “E” or any other annotation next to estimated values. If you cannot provide an estimate, enter “EN” for estimate not available.

10. Quantitative information should be reported to the nearest whole number (no decimal points) unless otherwise indicated. Do not use commas in numerical entries.

11. All design data should reflect the current or planned configuration of equipment.

GENERAL INSTRUCTIONS Continued

12. Enter the data in the unit of measurement requested. For example, if the actual cost is $14,586,625.43, and you are requested to report on the form in thousand dollars, then enter 14587.

13. If the plant or units are jointly owned, the plant operator (respondent) must submit the report for the entire plant, not just for the portion owned by any single owner.

14. The data reported on this form must be consistent with the corresponding data reported on other Energy Information Administration forms, e.g., total annual steam-electric generation reported on Schedule 5 of this form should equal the annual steam-electric generation reported on Form EIA-906, "Power Plant Report." Maximum generator nameplate rating should be the same as the nameplate rating reported on Form EIA-860, "Annual Electric Generator Report."

ITEM-BY-ITEM INSTRUCTIONS

Schedule 1. Identification

1. For line 1, **Company Name**, verify the name. This item represents the full legal name of the plant operator.

2. For line 2, **Current Address of Principal Business Office**, verify the principal name and address. Include an attention line, room number, building designation, etc.

3. For line 4, **Plant Code**, plant code may not be changed. If you have questions regarding the plant code, please call or e-mail the survey manager.

4. For line 5, **Plant Status**, and line 6, **Plant Type,** check the appropriate status and type.

5. For line7, **State**, insert the appropriate two-letter U.S. Postal Service abbreviation.

Schedule 2. Plant Configuration

1. Identification information should be a code commonly used by plant management for that equipment (e.g., "2," "A101," "7B," etc.). Select a code for each piece of equipment and use it for that equipment throughout this form. The code should be a maximum of six characters long and should conform to codes reported for the same equipment (especially generators) on other EIA forms. Do not use blanks in the code. Do not enter "NA" for those lines that are not applicable. Organic plants under 100 MW should only complete lines 1, 2, 3, and if applicable, 5 and 6. Planned equipment that is on order and expected to go into commercial service within 5 years must be reported. If two or more pieces of equipment (e.g., two generators) are associated with a single boiler, report each identification code, separated by commas, under the appropriate boiler. Do not change preprinted equipment identification.

2. For line 1, using each boiler as a starting point, complete the entire column under the boiler identification with the requested information on each piece of associated existing or planned equipment (e.g., generators, cooling systems, etc.). Report waste-heat boilers with auxiliary firing. Do not report waste-heat boilers without auxiliary firing, or auxiliary house or startup boilers. A waste-heat boiler is a boiler that receives all or a substantial portion of its energy input from the noncombustible exhaust gases of a separate fuel-burning process. Combined cycle units with auxiliary firing report the heat recovery steam generators (HRSGs) on line1.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 2. Plant Configuration (Continued)

3. For lines 2, 4, 5, 6, 7, and 8, if a piece of equipment (e.g., a generator or a cooling system) serves two or more boilers, repeat the identification information for that equipment under each appropriate boiler.
4. For line 2, **Associated Generator(s)**, do not report auxiliary, house, or emergency generators. Multiple generators operated as a single unit (e.g., cross compound and topping generators) should be identified as a group with one identification code. Combined cycle units with auxiliary firing report only the steam generators. Do not report the combustion turbine portion of the combined cycle unit.
5. For line 3, **Generator Associations with Boiler as Actual or Theoretical,** indicate “A” for actual association during year or “T” for theoretical associations.
6. For line 4, **Associated Cooling System(s)**, a cooling system is an equipment system that provides water to the condensers and includes water intakes and outlets, cooling towers and ponds, pumps, and pipes. Identify a single plant cooling system, not separate systems, unless systems are physically separated, e.g., have separate water intake and outlet structures, where each system can be operated independently.
7. For line 5, **Associated Flue Gas Particulate Collector(s)**, if a combination particulate collector is associated with a single boiler, identify the collectors as a single group. If the particulate collector also removes sulfur dioxide, identify the unit in lines 5 and 6 using the same identification code.
8. For line 6, **Associated Flue Gas Desulfurization Units(s)**, for reporting purposes identify an associated flue gas desulfurization unit to include all the trains (or modules) associated with a single boiler. If the flue gas desulfurization unit also removes particulate matter, identify the unit in lines 5 and 6 using the same identification code
9. For line 7, **Associated Stack(s)**, a stack is defined as a tall, vertical structure containing one or more flues used to discharge products of combustion into the atmosphere.
10. For line 8, **Associated Flue(s)**, a flue is defined as an enclosed passageway within a stack for directing products of combustion to the atmosphere. For stacks with multiple flues, report in one column all flues that serve the boiler identified in line 1. Separate multiple entries with commas. If the stack has a single flue, use the stack identification for the flue identification.

Schedule 3. Plant Information, Part A. Annual Byproduct Disposition and Useful Thermal Output

1. If no byproduct was produced, enter “NA” in column (f) for this item. If a byproduct is disposed of at no cost, enter the quantity of the byproduct under the appropriate column and make a footnote entry on Schedule 10 stating that no money was exchanged for the quantity indicated. If there was a cost for disposal, make sure there is a corresponding entry on Schedule 3, Part B, for collection and/or disposal costs. Costs for gypsum disposal (line 4) should be reported on Schedule 3, Part B, line 5, column (b), with a footnote entry on Schedule 10. Entries on Schedule 3, Part A, “Byproducts Sold,” column (d), must be compatible with entries on Schedule 3, Section B, lines 11 through 16, “Byproduct Sales Revenue.” If the byproduct was distributed in several different ways (for example, the byproduct was placed in a landfill and then later sold), report the end disposition of the byproduct and provide a footnote on Schedule 10 explaining all previous dispositions.
2. For line 6, check the appropriate box to indicate a topping cycle or a bottoming cycle system. Check “NA” if not a cogeneration facility.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 3. Plant Information, Part A. Annual Byproduct Disposition and Useful Thermal Output (continued)

3. For line 7, enter **Useful Thermal Output.** (Useful Thermal Output is the thermal energy made available in a combined-heat-and-power system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.)

4. For line 8, **How was the Useful Thermal Output used**, check the appropriate box(es).

Schedule 3. Plant Information, Part B. Financial Information

1. All entries should be reported in thousand dollars to the nearest whole number.

2. For all **Operation and Maintenance (O&M) Expenditures During Year**, costs should be provided for both collection and disposal of the indicated byproducts. If the collection and disposal costs cannot be separated, place the total cost under collection (column (a)), place an "EN" (estimate not available) under disposal (column (b)), and a footnote on Schedule 10 indicating that the costs cannot be separated. All operation and maintenance expenditures should exclude depreciation expense, cost of electricity consumed, and fuel differential expense (i.e., extra costs of cleaner, thus more expensive fuel). Include all contract and self-service pollution abatement operation and maintenance expenditures for each line item.

3. For line 1, **Fly Ash**, and line 2**, Bottom Ash**, expenditures cover all material and labor costs including equipment operation and maintenance costs (such as particulate collectors, conveyers, hoppers, etc.) associated with the collection and disposal of the byproducts.

4. For line 3, **Flue Gas Desulfurization**, expenditures cover all material and labor costs including equipment operation and maintenance costs associated with the collection and disposal of the sulfur byproduct. The total for line 3, columns (a) plus (b) (Flue Gas Desulfurization Collection and Disposal Costs) should be greater than or equal to the combination of all totals reported on Schedule 8, Part A, line 13 (Flue Gas Desulfurization Operation and Maintenance Expenditures During Year).

5. For line 4, **Water Pollution Abatement**, expenditures cover all operation and maintenance costs for material and/or supplies and labor costs including equipment operation and maintenance (pumps, pipes, settling ponds, monitoring equipment, etc.), chemicals, and contracted disposal costs. Collection costs include any expenditure incurred once the water that is used at the plant is drawn from its source. Begin calculating expenditures at the point of the water intake. Disposal costs include any expenditures incurred once the water that is used at the plant is discharged. Begin calculating disposal expenditures at the water outlet (i.e., cooling costs).

6. For line 5, **Other Pollution Abatement**, operation and maintenance expenditures are those not allocated to one particular expenditure (e.g., expenditures to operate an environmental protection office or lab). Include expenses for conducting environmental studies for expansion or reduction of operation. Exclude all expenses for health, safety, employee comfort (OSHA), environmental aesthetics, research and development, taxes, fines, permits, legal fees, Superfund taxes, and contributions. Define other pollution abatement(s) in a footnote(s) on Schedule 10.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 3. Plant Information, Part B. Financial Information (Continued)

7. For **Capital Expenditures for New Structures and Equipment During Year, Excluding Land and Interest Expense**, report all pollution abatement capital expenditures for new structures and/or equipment made during the reporting year regardless of the date they may become operational. Lines 7, 8, 9, and 10 should not be left blank. Enter "EN" if an estimate is not available, and "NA" if the item is not applicable. Specify the nature of the expenditures for these items in a footnote(s) on Schedule 10.

8. For line 7, **Air Pollution Abatement**, report new structures and/or equipment purchased to reduce, monitor, or eliminate airborne pollutants, including particulate matter (dust, smoke, fly ash, dirt, etc.), sulfur dioxides, nitrogen oxides, carbon monoxide, hydrocarbons, odors, and other pollutants. Examples of air pollution abatement structures/equipment include flue gas particulate collectors, flue gas desulfurization units, continuous emissions monitoring equipment (CEMs), and nitrogen oxide control devices. Specify new structures/equipment in a footnote on Schedule 10.

9. For line 8, **Water Pollution Abatement**, report new structures and or equipment purchased to reduce, monitor, or eliminate waterborne pollutants, including chlorine, phosphates, acids, bases, hydrocarbons, sewage, and other pollutants. Examples include structures/equipment used to treat thermal pollution; cooling, boiler, and cooling tower blowdown water; coal pile runoff; and fly ash waste water. Water pollution abatement excludes expenditures for treatment of water prior to use at the plant. Specify new structures/equipment in a footnote on Schedule 10.

10. For line 9, **Solid/Contained Waste**, report new structures/equipment purchased to collect and dispose of objectionable solids or contained liquids. Examples include purchases of storage facilities, trucks, etc., to collect, store, and dispose of solid/contained waste. Include equipment used for handling solid/contained waste generated as a result of air and water pollution abatement. Specify new structures/equipment in a footnote on Schedule 10.

11. For line 10, **Other Pollution Abatement**, report amortizable expenses and purchases of new structures and or equipment when such purchases are not allocated to a particular unit or item. Examples include charges for the purchases of facilities to control hazardous waste, radiation, and noise pollution. Exclude all equipment purchased for aesthetics purposes. Specify new structures/equipment in a footnote on Schedule 10.

12. If **Byproduct Sales Revenue During Year** items are not applicable, place an "NA" in line 16 only. Report under **Byproduct Sales Revenue** the revenue, if any, for each listed byproduct. Specify "other" revenue in a footnote on Schedule 10. Entries must be compatible with the entries on Schedule 3, Part A, column (d), sold. If the revenue for a byproduct is less than $1,000, leave the item blank and make a footnote entry on Schedule 10. Revenue for gypsum should be reported on Schedule 3, Part B, line 14, with a footnote entry on Schedule 10. Report the total revenue for the sale of byproducts on line 16. If the revenue reported was for the sale of stockpiled byproducts from previous years, make a footnote entry on Schedule 10.

Schedule 4. Boiler Information, Part A. Fuel Consumption and Quality

1. For each **Boiler ID** fill in the information by fuel code. If a plant uses fuel for reheaters or other fuel combustion devices where the exhaust gases exit the same stack as a main boiler(s), then report this separate fuel consumption under a fictitious boiler(s). Report a fictitious boiler for each stack that the exhaust gases exit. These boilers are to be identified as FB1, FB2, etc. Complete Schedule 4A for each fictitious boiler and include an entry on Schedule 2 showing the boiler(s) and the stack(s) used.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part A. Fuel Consumption and Quality (Continued)

2. If a common fuel feeder serves a group of boilers, so that individual boiler fuel consumption is not metered, estimate individual boiler fuel consumption.
3. For line 1, **Boiler Status**, select from the following equipment status codes:

Code	Boiler Status
CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service)

4. For line 1, **Hours Under Load During Year**, enter actual hours the boiler has operated to drive the generator producing electricity.
5. For lines 2 through 25, columns (a) and (f), **Fuel Code**, select a fuel code from the list of energy sources on pages xxi and xxii of this form.
6. For lines 2 through 25, columns (b) and (g), **Quantity**, enter amount of fuel consumed for electric power generation and thermal energy associated with the production of electricity. Include all fuel used in a cogeneration system, such as used for processed steam, direct heating, space heating, or thermal output delivered to other end users. Report the fuel codes BIT, LIG, SUB, WC, and PC to the nearest thousand tons. Report the fuel codes DFO, JF, KER, RFO, and WO in thousand barrels. Report the fuel code NG in thousand cubic feet. For all other fuel codes report solids in thousand tons, liquids in thousand barrels, and gases in thousand cubic feet. If you cannot report your fuel using the above units of measure, specify in a footnote on Schedule 10. Combined cycle units report only the auxiliary firing fuel associated with the HRSG. Do not report the fuel associated with the combustion turbine portion of the combined cycle unit
7. For lines 2 though 25, columns (c) and (h), **Heat Content**, report the heat content of the fuels burned in Btu. The heat content of the fuel should be reported as the gross or "higher heating value" (rather than the net or lower heating value). The higher heating value exceeds the lower heating value by the latent heat of vaporization of the water. The heating value of fuels generally used and reported in a fuel analysis, unless otherwise specified, is the higher heating value. If the fuel heat content cannot be reported, "as burned," data may be obtained from the fuel supplier on an "as received" basis. If this is the case, indicate in a footnote on Schedule 10 that the fuel heat content data are "as received." Report the value in the following units: solids in Btu per pound; liquids in Btu per gallon; and gases in Btu per cubic foot.
8. For lines 2 through 25, **Sulfur Content and Ash Content**, columns (d) and (e), (i) and (j), report content to nearest 0.01 percent for sulfur and the nearest 0.1 percent for ash. Sulfur content should be reported for the fuel codes BIT, LIG, SUB, WC, SC, DFO, JF, KER, RFO, and WO. Ash content should be reported for the fuel codes BIT, LIG, SUB, WC, and SC.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part A. Fuel Consumption and Quality (Continued)

9. For lines 26 through 29, columns (a) and (b), enter the fuel code and the summed quantity of fuel consumed in the year for each of the fuel codes reported in lines 2 through 25.

10. For line 30, **Sampling Procedure**, select from the following codes. If you select "other" please specify in a footnote in Section 10.

Code	Sampling Procedure
PM	Proximate
UM	Ultimate
CD	Continuous drip method
GC	Gas chromatography
GB	Grab
OT	Other

11. For line 31, **Method of Analysis**, indicate the predominant method for determining the properties reported for the boiler. Report ASTM or GPA codes for the boiler method of analysis. These codes are found on test result data or invoices from most testing labs.

12. For line 32, **Laboratory Performing Analysis**, identify the laboratory most frequently used to analyze the primary fuel for the boiler. If the plant's operating company performed the analysis, indicate "internal."

Schedule 4. Boiler Information, Part B. Air Emissions Standards

1. Complete a separate page for each existing or planned boiler.

2. For line 2, **Type of Boiler Standards Under Which The Boiler Is Operating,** indicate the standards as described in the U.S. Environmental Protection Agency regulation under 40 CFR. Select from the following codes of the New Source Performance Standards (NSPS):

Code	Standard Type
D	Subpart D is the Standards of Performance for fossil-fuel fired steam boilers for which construction began after August 17, 1971.
Da	Subpart Da is the Standards of Performance for fossil-fuel fired steam boilers for which construction began after September 18, 1978.
Db	Subpart Db is the Standards of Performance for fossil-fuel fired steam boilers for which construction began after June 19, 1984.
Dc	Subpart Dc is the Standards of Performance for small industrial-commercial-institutional steam generating units.
N	Not covered under New Source Performance Standards.

3. For line 3, **Type of Statute or Regulation,** select from the following the most stringent type of statute or regulation code:
   FD Federal
   ST State
   LO Local

4. If there is no standard for nitrogen oxide emissions, report "NA" for line 3, column (c), and skip the remaining column (c) items.

5. Line 4, **Emission Standard Specified**, refers to the numeric value for the unit of measurement in line 5. If no numeric value is specified, report "NA." For Sulfur Dioxide (column (b)), if the standard requires both an emission rate and a percent scrubbed, report both standards separated by a slash (e.g., 1.2/90 for emission standards specified in line 4, column (b), and pounds of sulfur dioxide per million Btu in fuel/percent sulfur removal efficiency (by weight) for units of measurement in line 5, column (b), and indicate in a footnote on Schedule 10.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part B. Air Emissions Standards (Continued)

6. For line 5, **Unit of Measurement Specified**, column a, Particulate Matter, select from the following unit of measurement codes (PB* is the preferred measurement):

Code	Unit of Measurement
OP	Percent of opacity
PB*	Pounds of particulate matter per million Btu in fuel
PC	Grains of particulate matter per standard cubic foot of stack gas
PG	Pounds of particulate matter per thousand pounds of stack gas
PH	Pounds of particulate matter emitted per hour
UG	Micrograms of particulate matter per cubic meter
OT	Other (specify in a footnote on Schedule 10)

7. For line 5, **Unit of Measurement Specified**, column (b), Sulfur Dioxide, select from the following unit of measurement codes (DP* is the preferred measurement):

Code	Unit of Measurement
DC	Ambient air quality concentration of sulfur dioxide (parts per million)
DH	Pounds of sulfur dioxide emitted per hour
DL	Annual sulfur dioxide emission level less than a level in a previous year
DM	Parts per million of sulfur dioxide in stack gas
DP*	Pounds of sulfur dioxide per million Btu in fuel
SB	Pounds of sulfur per million Btu in fuel
SR	Percent sulfur removal efficiency (by weight)
SU	Percent sulfur content of fuel (by weight)
OT	Other (specify in a footnote on Schedule 10)

8. For line 5, **Unit of Measurement Specified**, column (c), Nitrogen Oxides, select from the following unit of measurement codes (NP* is the preferred measurement):

Code	Unit of Measurement
NH	Pounds of nitrogen oxides emitted per hour
NL	Annual nitrogen oxides emission level less than a level in a previous year
NM	Parts per million of nitrogen oxides in stack gas
NO	Ambient air quality concentration of nitrogen oxides (parts per million)
NP*	Pounds of nitrogen oxides per million Btu in fuel
OT	Other (specify in a footnote on Schedule 10)

9. For line 6, **Time Period Specified**, select from the following codes to indicate the period over which measurements were averaged:

Code	Time Period
NV	Never to exceed
FM	5 minutes
SM	6 minutes
FT	15 minutes
OH	I hour
WO	2 hours
TH	3 hours
EH	8 hours
DA	24 hours
WA	Weekly average
MO	30 days
ND	90 days
YR	Annual
PS	Periodic stack testing
DT	Defined by testing
NS	Not specified
OT	Other (specify in a footnote on Schedule 10)

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part B. Air Emissions Standards (Continued)

10. For line 7, **Year Boiler Was or Is Expected to Be in Compliance With Federal, State and/or Local Regulations**, if the boiler is currently in compliance, enter the year the boiler came into compliance or the year of the regulation, whichever came last. Report "9999" only if a revision of a governing regulation is being sought or no plans have been approved to bring the boiler into compliance.

11. For line 8, **If Not in Compliance, Strategy for Compliance**, column (c), select from the following strategy for compliance codes (separate multiple entries (up to three) with commas):

Code	Strategy for Compliance
BO	Burner out of service
FR	Flue gas recirculation
LA	Low excess air
LN	Low nitrogen oxide burner
MS	Currently meeting standard
NC	No plans to control
OV	Overfire air
SE	Seeking revision of governing regulation
OT	Other (specify in a footnote on Schedule 10)

12. For line 9, **Existing,** and line 10, **Planned, Strategies to Meet the Sulfur Dioxide Requirements of Title IV of the Clean Air Act Amendment of 1990**, column (b), select from the following strategy for compliance codes (separate multiple entries (up to three) with commas):

Code	Strategy for Compliance
CU	Control unit under Phase I extension plan
IF	Install flue gas desulfurization unit (other than Phase I extension plan)
NC	No change in historic operation of unit anticipated
ND	Not determined at this time
RP	Repower Unit
SS	Switch to lower sulfur fuel
SU	Designate Phase II unit(s) as substitution unit(s)
TU	Transfer unit under Phase I extension plan
UC	Decrease utilization - designate Phase II unit(s) as compensating unit(s)
UE	Decrease utilization - rely on energy conservation and/or improved efficiency
US	Decrease utilization - designate sulfur-free generators to compensate
UP	Decrease utilization - purchase power
WA	Allocated allowances and/or purchase allowances
OT	Other (specify in a footnote on Schedule 10)

Schedule 4. Boiler Information, Part C. Design Parameters

1. Complete for each existing or planned boiler. If a procurement contract has been signed for an upgrade or retrofit of a boiler: 1) complete a separate page for the existing boiler; 2) explain on Schedule 10 (footnotes) how long the existing equipment will be out of service; and 3) using the same boiler identification, complete a separate Schedule 4 Part C for the planned upgrade or retrofit.

2. For line 2, **Boiler Actual or Projected Inservice Date**, and line 3, **Boiler Actual or Projected Retirement Date**, the month-year date should be entered as follows: August 1959 as 8-1959. If the month is unknown, use the month of June as a default and enter a 6 before the year.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part C. Design Parameters (Continued)

3. For line 4, **Boiler Manufacturer**, select one code from the following boiler manufacturers' codes:

Code	Boiler Manufacturer
AI	Aalborg Industries
AL	Alstrom
AS	American Shack
AT	Applied Thermal Systems
BR	BROS
BW	Babcock and Wilcox
CE	Combustion Engineering
DJ	De John Coen bv
DL	Deltak
DS	Doosan
EC	Econotherm
ER	Erie City Iron Works
FW	Foster Wheeler
GE	General Electric
GT	Gotaverken
HT	Hitachi
ID	Indeck
IN	Innovative Steam Technology
KL	Keeler Dorr Oliver
KP	Kvaerner Pulping
KW	Kawasaki Heavy Industries
NT	Nooter/Erickson
PB	Peabody
PR	Pyro Power
RS	Riley Stoker
ST	Sterling
TM	Tampell
TS	Toshiba
VO	Vogt Machine Company
WE	Westinghouse
WG	Wiegl Engineering
WI	Wickes
ZN	Zurn
OT	Other (specify in a footnote on Schedule 10)

4. For line 5, **Type of Firing Used with Primary Fuels**, select from the following firing codes (separate multiple entries (up to three) with commas):

Firing Code	Firing Type Description
AF	Arch firing
CF	Concentric firing
CY	Cyclone firing
DB	Duct burner
FB	Fluidized bed firing
FF	Front firing
OF	Opposed firing
RF	Rear firing
SF	Side firing
SS	Spreader stoker
TF	Tangential firing
VF	Vertical firing (burners mounted on furnace ceiling)
OT	Other (specify in a footnote on Schedule 10)

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part C. Design Parameters (Continued)

5. For lines 7 through 10, enter firing rate data for primary or alternate fuels as entered in lines 12 and 18. Do not enter firing rate for startup or flame stabilization fuels. For waste-heat boilers with auxiliary firing, enter the firing rate for auxiliary firing and complete line 11 for waste heat.
6. For line 11, a waste-heat boiler is a boiler that receives all or a substantial portion of its energy input from the noncombustible exhaust gases of a separate fuel-burning process.
7. For line 12, **Primary Fuels Used**, see pages xxi and xxii for a list of fuel codes. Show design firing rates for each fuel in the associated lines 7, 8, 9, and 10. Do not include startup fuels. Predominance is based on Btu.
8. For line 15, **Total Air Flow**, report at standard temperature and pressure, i.e., 68 degrees Fahrenheit and one atmosphere pressure.
9. For line 16, **Wet or Dry Bottom**, enter “W” for Wet or “D” for Dry. **Wet Bottom** is defined as slag tanks that are installed at furnace throat to contain and remove molten ash from the furnace. **Dry Bottom** is defined as having no slag tanks at furnace throat area; throat area is clear; bottom ash drops through throat to bottom ash water hoppers. This design is used where the ash melting temperature is greater than the temperature on the furnace wall, allowing for relatively dry furnace wall conditions.

Schedule 4. Boiler Information, Part D. Nitrogen Oxide Emission Controls

1. Complete a separate page for each existing or planned boiler.
2. For line 2, **Nitrogen Oxide Control Status**, select from the following status codes:

Code	Control Status
CN	Cancelled (previously reported as “planned”)
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
OZ	Operated during the ozone season (May through September)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve); i.e., not normally used, but available for service
SC	Cold Standby (Reserve); deactivated (usually requires 3 to 6 months to reactivate)
TS	Operating under test conditions (not in commercial service)

3. For line 4, **Low Nitrogen Oxide Control Process**, select from the following low nitrogen oxide control processes (separate multiple entries (up to three) with commas):

Code	Control Process
AA	Advanced Overfire Air
BF	Biased Firing (alternate burners)
CF	Fluidized Bed Combustor
FR	Flue Gas Recirculation
FU	Fuel Reburning
LA	Low Excess Air
LN	Low NOx Burner
NA	Not Applicable
OV	Overfire Air
SC	Slagging
SN	Selective Noncatalytic Reduction
SR	Selective Catalytic Reduction
OT	Other (specify in a footnote on Schedule 10)

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part D. Nitrogen Oxide Emission Controls (Continued)

4. For line 5, **Manufacturer of Low Nitrogen Oxide Control Burners**, select from the following low nitrogen oxide control burner manufacturers:

Code	Manufacturer
AB	Advanced Burner Technologies
AC	Advanced Combustion Technology
AL	Alstom
AT	Applied Thermal Systems
AU	Applied Utility Systems (AUS)
AZ	Alzeta
BC	Babcock Borsig Power
BM	Bloom
BW	Babcock and Wilcox
CE	Combustion Engineering
CM	Combustion Components Associates Inc
CN	Coen
DB	Deutsche-Babcock
DD	Damper Design Inc
DQ	Duquesne Light Company & Energy Systems Associates
DV	Davis
EA	Eagle Air
EG	Energy and Environmental Research Corp (EER)
EL	Electric power Technologies
EP	EPRI
ET	Entropy Technology and Environmental Construction Corp (ETEC)
FB	Faber
FN	Forney
FT	Fuel Tech Inc
FW	Foster Wheeler
GR	GE Energy and Environmental Research Corp (GEEER)
HL	Holman
IC	International Combustion Limited
ID	Indeck
IH	in house
JZ	John Zink Todd Combustion
KL	Keeler Dorr Oliver
MB	Mitsui-Babcock
MI	Mitsubishi Industries
MT	Mobotec
NA	Not Applicable
NB	Nebraska Boiler Company
NC	Natcom, Inc
NE	NEI
NL	Noell, Inc
PA	Procedair
PB	Peabody
PL	Pillard
PS	Peerless Manufacturing Company
PX	Phoenix Combustion
RD	Rodenhuis and Verloop
RJ	RJM
RR	Rolls Royce
RS	Riley Stoker
RV	RV Industries
SW	Siemans-Westinghouse
TM	Tampella
TS	Toshiba
WG	Weigel Engineering
ZC	Zeeco
OT	Other (specify in a footnote on Schedule 10)

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 4. Boiler Information, Part D. Nitrogen Oxide Emission Controls (Continued)

5. For line 6, **For Entire Year**, enter the controlled nitrogen oxide emission rate, in pounds per million Btu of the fuel, based on data from continuous emission monitors (CEMs) where possible. Where CEMs data are not available, report controlled nitrogen oxide emission rate based on the method used to report emissions data to environmental authorities.

6. For line 7, **For May through September Only,** enter the controlled nitrogen oxide emission rate, in pounds per million Btu of the fuel, based on data from CEMs where possible. Where CEMS data are not available, report controlled nitrogen oxide rates based on the method used to report emissions data to environmental authorities. The summer emission rate may be assumed to be equivalent to the annual emission rate where identical nitrogen oxide controls are used year round.

Schedule 4. Boiler Information, Part E. Mercury Emission Controls

1. For line 2, if “Yes” is checked on line 1, **Does This Boiler have Mercury Emission Controls**, mark all of the boxes that apply to the type of mercury emission controls used. If the type of control is “other”, please describe in Schedule 10, Footnotes.

Schedule 5. Generator Information

1. For line 1, **Generator ID**, complete a column for each existing, under construction, or planned generator. The identification must be the same as on Schedule 2, item 2.

2. For line 2**, Maximum Generator Nameplate Rating**, report the maximum generator nameplate rating in megawatts. If the nameplate rating is expressed in kilovoltamperes, convert to kilowatts by multiplying the power factor by the kilovoltamperes, then convert kilowatts to megawatts by dividing by 1,000. If more than one rating appears on the nameplate, select the highest rating. Do not indicate the nameplate rating of the turbine.

3. For line 3**, Design Flow Rate**, and line 4, **Design Temperature Rise**, the data for both items should be under the same operating conditions.

4. For line 3**, Design Flow Rate**, if more than one condenser serves the generator, report the total flow rate for all the condensers.

5. For line 4, **Design Temperature Rise**, if more than one condenser serves the generator, report the weighted average (by flow rate) temperature rise for all the condensers.

6. For lines 5 through 16, **Monthly Net Electrical Generation**, is the total amount of electric energy generated, measured at the generator terminals, minus the total electric energy consumed at the generating station (e.g., pumps, fans, and ancillary consumption) for the time period indicated. If the monthly service load exceeded monthly gross electrical generation, report negative electrical generation with a minus sign. Do not use parentheses. Report in megawatthours only. If no generation occurred, place a zero (0) in line 17 only. Combined cycle units with auxiliary firing capability report only the electrical generation associated with the heat recovery steam generator. Do not report the electrical generation associated with the combustion turbine portion of the combined cycle unit.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 6. Cooling System Information, Part A. Annual Operations

1. If actual data are not available, provide an estimated value.

2. If the source of cooling water is wells or municipal water systems, do not complete lines 7 through 10.

3. For line 2, **Cooling System Status**, select from the following equipment status codes:

Code	System Status
CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve); i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated (usually requires 3 to 6 months to reactivate)
TS	Operating under test conditions (not in commercial service)

4. For line 2, if the code selected is "OP," complete lines 3 through 10; otherwise do not complete these lines.

5. For line 3**, Annual Amount of Chlorine Added to Cooling Water**, pertains solely to elemental chlorine. If a compound is used, determine the amount of chlorine in the compound. If the amount of chlorine added to the cooling water is known for the entire plant but not for each cooling system, enter the information in column (a), enter "EN" in the rest of the columns as necessary, and indicate in a footnote on Schedule 10 that the information is for the entire plant. Report amount of chlorine to the nearest whole number in thousand pounds.

6. For line 5, **Discharge**, if the system is a closed, zero discharge system, report "0," complete lines 6, 7, and 8, but skip lines 9 and 10.

7. For lines 4, 5, and 6, if the **Average Annual Rate of Cooling Water** is known for the entire plant but not for each cooling system, enter the information in line 6, column (a), enter "EN" in the rest of the columns as necessary, and indicate in a footnote on Schedule 10 that the information is for the entire plant.

8. For lines 7, 8, 9, and 10, the "Peak Load Month" refers to the month of greatest plant electrical generation during the winter heating season (October-March) and summer cooling season (April-September), respectively. Report temperature to the nearest whole number.

Schedule 6. Cooling System Information, Part B. Design Parameters

1. If a procurement contract has been signed for an upgrade or retrofit of a cooling system: 1) complete a separate page for the existing cooling system; 2) explain on Schedule 10 (footnotes) how long the existing equipment will be out of service; and 3) using the same cooling system identification, complete a separate Schedule 6, Part B, for the planned upgrade or retrofit.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 6. Cooling System Information, Part B. Design Parameters

2. For line 3, **Type of Cooling System**, select from the following cooling system codes (separate multiple entries (up to four) with commas):

Code	Cooling System Description
OC	Once through with cooling pond(s) or canal(s)
OF	Once through, fresh water
OS	Once through, saline water
RC	Recirculating with cooling pond(s) or canal(s)
RF	Recirculating with forced draft cooling tower(s)
RI	Recirculating with induced draft cooling tower(s)
RN	Recirculating with natural draft cooling tower(s)
OT	Other (specify in a footnote on Schedule 10)

3. For line 4, **Source of Cooling Water**, and line 5, **Design Cooling Water Flow Rate**, if more than one source of water is used by a cooling system, enter other sources in a footnote on Schedule 10. If water is purchased, report “municipal.” If water is taken from wells, report “wells.” If source of water is “municipal” or “wells,” do not complete lines 18, 19, 20, and 21 and provide the total amount of water used at 100 percent load in line 5. Give the name of river, lake, etc.

4. For lines 7, 8, and 9, a cooling pond is a natural or man-made body of water that is used for dissipating waste heat from power plants.

5. For line 11, **Type of Towers**, select from the following cooling tower codes (separate multiple entries (up to two) with commas):

Code	Type of Towers
MD	Mechanical draft, dry process
MW	Mechanical draft, wet process
ND	Natural draft, dry process
NW	Natural draft, wet process
WD	Combination wet and dry processes

6. For lines 14, 15, 16, and 17, enter the actual installed cost for the existing system or the anticipated cost to bring a planned system into commercial operation. Installed cost should include the cost of all major modifications. A major modification is any physical change which results in a change in the amount of air or water pollutants or which results in a different pollutant being emitted.

7. For line 14, **Total System**, the cost should include amounts for items such as pumps, piping, canals, ducts, intake and outlet structures, dams and dikes, reservoirs, cooling towers, and appurtenant equipment. The cost of condensers should not be included.

8. For lines 18 through 21, if the cooling system is a zero discharge type (RC, RF, RI, RN), do not complete column (b). The intake and the outlet are the points where the cooling system meets the source of cooling water found on line 4. For all longitude and latitude coordinates, please provide degrees, minutes, and seconds.

9. For line 22, Enter Datum for Latitude and Longitude, if Known; Otherwise Enter “NA”:

   The longitude and latitude measurement for a location depends in part on the coordinate system (or “datum”) the measurement is keyed to. “Datum systems” used in the United States include the North American Datum 1927 (NAD27) and North American Datum 1983 (NAD83).

   If you know the datum system for the plant longitude and latitude, enter the system name (e.g., NAD83) on line 22. If you do not know the datum system used, enter NA.

   (For background information on datums and their uses, see: http://biology.usgs.gov/geotech/documents/datum.html)

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 7. Flue Gas Particulate Collector Information

1. For line 3, **Flue Gas Particulate Collector Status**, select from the following equipment status codes:

Code	Status
CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service).

2. For line 4, **Type of Flue Gas Particulate Collector**, select from the following flue gas particulate collector codes (for combination units, separate multiple entries (up to three) with commas):

Code	Description
BS	Baghouse, shake and deflate
BP	Baghouse, pulse
BR	Baghouse, reverse air
EC	Electrostatic precipitator, cold side, with flue gas conditioning
EH	Electrostatic precipitator, hot side, with flue gas conditioning
EK	Electrostatic precipitator, cold side, without flue gas conditioning
EW	Electrostatic precipitator, hot side, without flue gas conditioning
MC	Multiple cyclone
SC	Single cyclone
WS	Wet scrubber
OT	Other (specify in a footnote on Schedule 10 of the form).

3. For line 5, **Installed Cost of Flue Gas Particulate Collector Excluding Land**, enter the actual installed cost for the existing system or the anticipated cost to bring a planned system into commercial operation. Installed cost should include the cost of all major modifications. A major modification is any physical change which results in a change in the amount of air or water pollutants or which results in a different pollutant being emitted.

4. For line 7, **Typical Particulate Emissions Rate at Annual Operating Rate,** enter the particulate emission rate based on the annual operating factor (to nearest 0.01 pound per million Btu).

5. For lines 8 and 9, if the collector has a combination of components (i.e., a baghouse and an electrostatic precipitator) enter both components as one unit in one column. If the particulate collector also removes sulfur dioxide, enter the particulate scrubbing process in this section and the desulfurization process on Schedule 8, Part A.

6. For line 8, **At Annual Operating Factor**, enter removal efficiency based on the annual operating factor. Annual operating factor is defined as annual fuel consumption divided by the product of design firing rate and hours of operation per year. If actual data are unavailable, provide estimates based on equipment design performance specifications.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 7. Flue Gas Particulate Collector Information (Continued)

7. For line 9, **At 100 Percent Load or Tested Efficiency**, if the test was conducted, but not at 100 percent load, enter the efficiency on Schedule 7 and provide the load at which the test was conducted in a footnote on Schedule 10. If no test has been conducted, input "NA" in lines 9 and 10. Test results should not be noted if there was no test date.
8. For line 10, **Date of Most Recent Efficiency Test,** enter test date. If an efficiency test has never been performed, input "NA" in line 10 and specify in a footnote in Schedule 10.
9. For lines 11,12, 13, and 14, enter value for fuel. Enter range of values, if applicable.

Schedule 8. Flue Gas Desulfurization Unit Information, Part A. Annual Operations

1. For line 2**, Flue Gas Desulfurization Unit Status**, select from the following equipment status codes:

Code	Status
CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service)

If the code selected is "OP" complete lines 3 through 13, otherwise do not complete these lines.

2. For line 3, **Hours In-Service During Year**, enter the total number of hours one or more trains (or modules) were in operation; do not report for individual trains.
3. For lines 6 and 7, if the flue gas desulfurization unit also removes particulate matter, enter the desulfurization process in this section and the particulate scrubbing process on Schedule 7, **Flue Gas Particulate Collector Information**.
4. For line 6, **At Annual Operating Factor,** enter removal efficiency based on the annual operating factor. Annual operating factor is defined as annual fuel consumption divided by the product of design firing rate and hours of operation per year. If actual data are unavailable, provide estimates based on equipment design performance specifications.
5. For line 7, **At 100 Percent Load or Tested Efficiency,** if the test was conducted, but not at 100 percent load, enter the efficiency on Schedule 8, Part A, and provide the load at which the test was conducted in a footnote on Schedule 10. If no test was conducted, input "NA" in lines 7 and 8. Test results should not be given without a test date.
6. For lines 9, 10, 11, 12, and 13 enter expenditures to the nearest whole number. **Flue Gas Desulfurization Operation and Maintenance Expenditures** should include the costs of continuous emissions monitoring, raw and byproduct material handling, limestone milling and storage, dewatering facilities, contracted labor, and all other auxiliary flue gas desulfurization support facilities excluding depreciation expense and cost of electricity. These costs should also be included in line 3, Schedule 3, Part B.

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 8. Flue Gas Desulfurization Unit Information, Part B. Design Parameters (Continued)

2. For line 3, **Type of Flue Gas Desulfurization Unit**, select from the following FGD unit codes (for combination units, separate multiple entries (up to four) with commas):

Code	Type of Unit
BR	Jet Bubbling Reactor
CD	Circulating Dry Scrubber
MA	Mechanically aided type
PA	Packed type
SD	Spray dryer type
SP	Spray type
TR	Tray type
VE	Venturi type

3. For line 4, **Type of Sorbent**, select from the following sorbent codes (separate multiple entries (up to four) with commas):

Code	Type of Sorbent
AF	Alkaline fly ash
CC	Calcium carbide slurry
DB	Dibasic acid
DL	Dolomitic limestone
LA	Lime and alkaline fly ash
LF	Limestone and alkaline fly ash
LI	Lime
LS	Limestone
MO	Magnesium oxide
SA	Soda ash
SC	Sodium carbonate
SL	Soda liquor
SS	Sodium sulfite
OT	Other (specify in a footnote on Schedule 10)

4. For line 6, **Flue Gas Desulfurization Unit Manufacturer**, select one code from the following flue gas desulfurization unit manufacturer codes:

Code	Manufacturer
AM	American Air Filter
BW	Babcock and Wilcox
CC	Chemico
CE	Combustion Engineering
CO	Combustion Equipment
DM	Davey McKee
EE	Environmental Engineering
FL	Flakt, Inc.
FM	FMC
GE	General Electric
JO	Joy Manufacturing
KE	M. W. Kellogg
KR	Krebs Engineers
MI	Mitsubishi Industry
PB	Peabody
RC	Research Cottrell
RS	Riley Stoker
TH	Thyssen/CEA
UO	Universal Oil Products
OT	Other (specify in a footnote on Schedule 10)

ITEM-BY-ITEM INSTRUCTIONS Continued

Schedule 8. Flue Gas Desulfurization Unit Information, Part B. Design Parameters (Continued)

5. For line 15, **Removal Efficiency for Sulfur Dioxide**, report the removal efficiency as the percent by weight of gases removed from the flue gas.

6. For lines 20, 21, 22, and 23, enter the actual installed costs for the existing systems or the anticipated costs to bring a planned system into commercial operation. Installed cost should include the cost of all major modifications. A major modification is any physical change which results in a change in the amount of air or water pollutants or which results in a different pollutant being emitted. The total (line 23) will be the sum of lines 20, 21, and 22, which includes any other costs pertaining to the installation of the unit.

Schedule 9. Stack and Flue Information—Design Parameters

1. If a procurement contract has been signed for an upgrade or retrofit of a stack or flue: 1) complete a page for the existing stack or flue; 2) explain on Schedule 10 (footnotes) how long the existing structure will be out of service; and 3) using the same flue and stack identifications, complete a separate Schedule 9, Part B for the planned upgrade or retrofit.

2. For line 1, **Flue ID**, and line 2**, Stack ID**, there must be an entry. If there is only one flue, use the stack ID also as the flue ID. Identification codes must be the same as reported on Schedule 2.

3. For line 3, **Stack (or Flue) Actual or Projected In-Service Date of Commercial Operation**, the month-year should be entered as follows: August 1959 as 08-1959.

4. For line 4, **Status of Stack**, select one from the following equipment status codes:

Code	Status
CN	Cancelled (previously reported as “planned”)
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service)

5. For lines 7 and 8, rate should be approximately equal to cross-sectional area multiplied by the velocity, multiplied by 60.

6. For lines 13 and 14, seasonal average flue gas exit temperatures should be reported in degrees Fahrenheit, based on the arithmetic mean of measurements during operating hours. Summer season includes June, July, and August. Winter season includes January, February, and December.

7. For line 15, **Source**, enter “M” for measured or “E” for estimated.

8. For lines 16 and 17, **Stack Location**, enter the latitude and longitude in degrees, minutes, and seconds.

Schedule 9. Stack and Flue Information—Design Parameters (Continued)

9. For line 18, Enter Datum for Latitude and Longitude, if Known; Otherwise Enter "NA":

   The longitude and latitude measurement for a location depends in part on the coordinate system (or "datum") the measurement is keyed to. "Datum systems" used in the United States include the North American Datum 1927 (NAD27) and North American Datum 1983 (NAD83).

   If you know the datum system for the plant longitude and latitude, enter the system name (e.g., NAD83) on line 18. If you do not know the datum system used, enter NA.

(For background information on datums and their uses, see: http://biology.usgs.gov/geotech/documents/datum.html)

Schedule 10. Footnotes

The footnote reference can only refer to one page, one schedule and part, one equipment ID, and one line number and column letter. If the footnote is the same for multiple references, indicate this in the "notes" section. If the comment exceeds one line, repeat the page, schedule, part, line, and column identification. If "OT" is used instead of a specific code, please explain what it represents. Note preprinted text in comment section. Do not repeat a preprinted footnote again as this could result in a duplication.

ENERGY SOURCE TABLE

	Energy Source Code	Unit Label	"Higher Heating Value" Range Btu per unit of fuel: Low Value	High Value	Energy Source Description
	Fossil Fuels				
Coal and Syncoal	BIT	pound	10,000	14,500	Anthracite Coal and Bituminous Coal.
	LIG	pound	5,000	7,250	Lignite Coal.
	SC	pound	5,000	17,500	Coal-based Synfuel. Including briquettes, pellets, or extrusions, which are formed by binding materials or processes that recycle materials.
	SUB	pound	7,500	10,000	Subbituminous Coal.
	WC	pound	3,250	8,000	Waste/Other Coal. Including anthracite culm, bituminous gob, fine coal, lignite waste, waste coal.
Petroleum Products	DFO	gallon	130,952	147,619	Distillate Fuel Oil. Including Diesel, No. 1, No. 2, and No. 4 Fuel Oils.
	JF	gallon	119,048	142,857	Jet Fuel.
	KER	gallon	133,333	145,238	Kerosene.
	PC	pound	12,000	15,000	Petroleum Coke.
	RFO	gallon	138,095	161,905	Residual Fuel Oil. Including No. 5, No. 6 Fuel Oils, and Bunker C Fuel Oil.
	WO	gallon	71,429	138,095	Waste/Other Oil. Including Crude Oil, Liquid Butane, Liquid Propane, Oil Waste, Re-Refined Motor Oil, Sludge Oil, Tar Oil, or other petroleum-based liquid wastes.
Natural Gas and Other Gases	BFG	cubic foot	70	120	Blast Furnace Gas.
	NG	cubic foot	800	1,100	Natural Gas.
	OG	cubic foot	320	3,300	Other Gas - Specify in Comment Section.
	PG	cubic foot	2,500	2,750	Gaseous Propane.
	Renewable Fuels				
Solid Renewable Fuels	AB	pound	4,500	9,000	Agricultural Crop Byproducts/Straw/Energy Crops.
	MSW	pound	4,500	6,000	Municipal Solid Waste.
	OBS	pound	4,000	12,500	Other Biomass Solids. Specify in Comment Section.
	TDF	pound	8,000	16,000	Tire-derived Fuels.
	WDS	pound	3,500	9,000	Wood/Wood Waste Solids. Including paper pellets, railroad ties, utility poles, wood chips, bark, & wood waste solids.

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ENERGY SOURCE TABLE

	Energy Source Code	Unit Label	"Higher Heating Value" Range Btu per unit of fuel Low Value	 High Value	Energy Source Description
	Renewable Fuels continued				
Liquid Renewable (Biomass) Fuels	OBL	gallon	83,333	95,238	Other Biomass Liquids. Specify in Comment Section
	SLW	pound	5,000	8,000	Sludge Waste
	BLQ	pound	5,000	7,000	Black Liquor
	WDL	gallon	190,476	333,333	Wood Waste Liquids excluding Black Liquor. Includes red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids.
Gaseous Renewable (Biomass) Fuels	LFG	cubic foot	300	600	Landfill Gas
	OBG	cubic foot	360	1,600	Other Biomass Gas. Includes digester gas, methane, and other biomass gasses. Specify in Comment Section.
All Other Energy Sources	**All Other Energy Sources**				
	PUR	N/A	0	0	Purchased Steam
	OTH	N/A	0	0	Specify in Comment Section

U.S. Department of Energy Energy Information Administration Form EIA-767 (2005)	***STEAM-ELECTRIC PLANT OPERATION AND DESIGN REPORT***	**Form Approved OMB No. 1905-0129 Approval Expires: 11/30/2007**

GLOSSARY	The glossary for this form is available online at the following URL: http://www.eia.doe.gov/glossary/index.html
SANCTIONS	The timely submission of Form EIA-767 by those required to report is mandatory under Section 13(b) of the Federal Energy Administration Act of 1974 (FEAA) (Public Law 93-275), as amended. Failure to respond may result in a penalty of not more than $2,750 per day for each civil violation, or a fine of not more than $5,000 per day for each criminal violation. The government may bring a civil action to prohibit reporting violations, which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements. **Title 18 U.S.C. 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**
REPORTING BURDEN	Public reporting burden for this collection of information is estimated to average 66.3 hours per response for plants greater than or equal to 100 megawatts and 3.4 hours for plants 10 megawatts or greater but less than 100 megawatts. These estimates include the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Statistics and Methods Group, EI-70, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585-0670; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. A person is not required to respond to the collection of information unless the form displays a valid OMB number.
CONFIDENTIALITY	Except as noted below, any information reported on Form EIA-767 will not be treated as confidential and may be publicly released in identifiable form. In addition to the use of the information by the Energy Information Administration (EIA) for statistical purposes, the information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes. The information contained on Schedule 6, Part B and Schedule 9 of the Form EIA-767 relating to Latitude and Longitude will be kept confidential and not disclosed to the public to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905. The EIA will protect your information in accordance with its confidentiality and security policies and procedures. The Federal Energy Administration Act requires the EIA to provide company-specific data to other Federal agencies when requested for official use. The information reported on this form may also be made available, upon request, to another component of the Department of Energy (DOE); to any Committee of Congress, the General Accounting Office, or other Federal agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order. The information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes. Disclosure limitation procedures are applied to the statistical data published from Form EIA-767 confidential survey information to ensure that the risk of disclosure of identifiable information is very small.