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An Introduction to Steam Power Plant Water Supply and Plant Testing

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J. Paul Guyer, P.E., R.A.

CONTENTS

1. WATER SUPPLY

2. TESTING

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(Figures, tables and formulas in this publication may at times be a little difficult to read, but they are the best available. **DO NOT PURCHASE THIS PUBLICATION IF THIS LIMITATION IS NOT ACCEPTABLE TO YOU.)**

1. WATER SUPPLY. Raw water is required for supply to water treatment equipment for boiler-turbine cycle water fill and makeup, water treatment equipment backwash, plant service water, domestic (potable) water, ash conditioning, cooling tower system fill and makeup, and fire protection. Consider the use of a raw water storage tank if necessary to back up any uncertainties in water supply or for firefighting. Provide in-plant overhead tank or outdoor elevated tank for pressurization of distribution system, or consider the use of a pneumatic ground floor level pressurized system.

1.2 WATER MAKEUP

1.2.1 CYCLE MAKEUP. Boiler-turbine cycle water makeup is a requirement and continuous demand when the boiler-turbine cycle is in operation. Normal operation of the power plant will usually require an actual condensate makeup rate to the cycle of about 0.5 percent plus the makeup required for steam atomization of oil burners, steam operated soot blowers, and condensate losses in a process or facility heating system which is supplied with steam from the boiler-turbine cycle. The design of the makeup system should be based on a demand of 1.5 percent of the main steam flow to the turbine to provide for condensate losses from the cycle, plus steam usage for oil atomization and steam soot blowers, plus process or heating system steam and condensate losses.

1.2.2 COOLING TOWER MAKEUP. Makeup water to a cooling tower cooling water system is required to replace losses from evaporation, drift, and blowdown. Drift loss from a mechanical draft tower will range from a minimum of 0.03 percent to a maximum of 0.2 percent of the cooling water flow rate. The blowdown rate will depend on the number of concentrations of total dissolved solids to be maintained in the cooling water. The relationships of these variables are as follows:

Drift + Blowdown = Evaporation/(No. of Concentrations – 1)

Makeup = Evaporation + Drift + Blowdown

1.2.3 WATER TREATMENT. Water treatment equipment will be required to provide cycle water fill and makeup of suitable quality. The final quality will depend on the operating pressure of the boiler. Water treatment of raw water may also be required in conjunction with cycle water makeup treatment and/or to provide potable water for domestic use, all depending on the quality of the raw water supply. Where a demineralizer is used for cycle water makeup, it shall be sized as follows:

$$\text{Gallons/day} = (0.015 \times F \times 24 \times 60) + SA + SB + P) / 500 \qquad \text{(eq 1)}$$

where:

F = Maximum boiler steam flow, lb/h
SA = Atomizing steam requirements, gal/day
SB = Soot blower steam requirements, gal/day
P = Process or heating steam and condensate losses, gal/day

The demineralizer should be sized to produce the amount of water as determined by Equation 1 by operating the demineralizer 18 hours per day, leaving 6 hours per day for demineralizer regeneration. The sizing should also be such that it should not be necessary to regenerate the demineralizer more than once per day.

1.2.4 COOLING WATER SYSTEMS

1.2.4.1 ONCE-THROUGH SYSTEM. Once-through systems have an intake structure including screens, cooling water pumps to provide for water static and dynamic head losses, a condenser, conduits to carry the water, and a discharge or outfall structure located so that significant recirculation of warm water will not occur.

1.2.4.2 RECIRCULATING SYSTEM

1.2.4.2.1 EVAPORATIVE WET COOLING. This system utilizes cooling towers (natural or mechanical draft) or basins.

1.2.4.2.2 NON-EVAPORATIVE DRY COOLING. Cooling water is pumped through a closed circuit passing through the condenser where heat is absorbed, then through a water-to-air heat exchanger, and finally back to the cooling water pumps for recycling.

1.2.4.2.3 COMBINATION WET AND DRY COOLING. This system uses a combination of wet and dry systems as described above. The cooling tower combines a water to air heat exchanger section with an evaporative type cooling section. The advantages of the wet/dry tower as compared to the wet tower are lower water consumption and reduced water vapor (plume) discharge.

1.2.5 INTAKE STRUCTURES. The intake structure, usually made of concrete, shall contain stationary and mechanical traveling screens that are used to remove debris from the cooling water before entering the pumps.

1.2.5.1 LOCATION. Locate the intake structure as close to the water source as possible in order to limit the hydraulic losses to the pump suction and to eliminate the possibility of a sand silt buildup in the wells of the structure. Connect the structure with the power plant through suitable pipes or reinforced concrete flumes or tunnels. The intake structure shall be provided with access roads and power wiring.

1.2.5.2 ARRANGEMENT. Provide at least two parallel sets of wells in the structure to permit alternate operation when one set is being cleaned. Each set shall contain an entry well, with a trash rack in front and a sluice gate (or stop logs) at its outlet; a screen well, with a traveling water screen; and a crossover well with sluice gates to permit closing off the screen well and directing the water flow from either set of wells to a selected pump flume or pump well. The pump chamber may be combined with the intake structure when the power plant is some distance away or they may be separated by flume or pipe when they are close by and the pumps are installed near the condensers. In the combination intake structure and pump chamber, vertical centrifugal pumps are usually installed above a wet well, whereas horizontal centrifugal pumps may be installed in a dry well below low water level. A determination of extreme low and high water levels of the water source must be made.

1.2.5.3 TRASH RACKS. Inlet ports to the entry wells should be covered with trash racks as a rough screen for such items as logs, sticks, leaves, and ice. They should be designed to pass maximum velocities of 2 feet per second at extreme low water levels and arranged for manual raking from the outside.

1.2.5.4 TRAVELING WATER SCREEN

a) Use screen approach water velocities of 0.5 to 0.75 feet per second to avoid entrapment of fish.

b) The maximum water velocity through the net screen area when passing the circulating pump capacity should not exceed 2.5 feet per second at extreme low water level. The net screen area is one-half of the waterway area, after deducting for the screen frame and boot interference. Manufacturers will guarantee a maximum 2 feet head loss under the above conditions.

c) One or two speed drives are available, the higher speed for intermittent operation when debris is light and the lower speed for continuous operation when the debris is heavy.

d) Select screen size and material to suit water conditions. Provide a trash trench, backwash pump and dewatering bin for cleaning the screens. Trash cannot be pumped back into water, but is disposed of either by incineration or in a landfill.

e) The flow area below the extreme low water level and the extreme high water level determines the height of the traveling screen.

f) In the extreme case of large quantities of water plants and algae, it may be necessary to back up the traveling screen with a fine stationary screen that can be lifted out for cleaning.

1.2.5.5 PUMPS. Each condenser circulating pump should be sized to serve half of a condenser plus the water quantity required for turbine lubricating oil coolers, generator air coolers, and closed cooling water system. Oversizing these pumps will result in wasted power and in premature wear from operating continuously at pumping heads less than the design point. Pump materials should be suitable for the water conditions.

1.2.5.5.1 VERTICAL PUMPS. Use vertical pumps for large differences in extreme high and low water levels and obtain manufacturers' recommendations on installation. Design the suction chamber in accordance with technical recommendations, because these pumps are very sensitive to poor distribution of flow at suction bell entrances. Note that the distance of the bell from the bottom of the well is critical.

1.2.5.5.2 HORIZONTAL PUMPS. Where economically justified, use horizontally split centrifugal pumps in a dry well below extreme low water level to avoid the necessity of foot valves and priming, as they are not as sensitive as vertical pumps to inlet flow conditions. Where horizontal circulating pumps are located away from the intake structure but above the suction flume, provide a means of priming the pumps.

1.2.5.5.3 BACKWASH PUMP. The backwash pump for a traveling screen should be of the horizontally split centrifugal type and should take its suction from the circulating pump discharge. Where the intake structure and the circulating pump chamber are separated, it will be necessary to install a vertical backwash pump in the traveling screen well after the screen and to lengthen the intake structure accordingly. A fire pump, where required, may be installed in the crossover well of the intake structure. Provide space for pump motor controllers, traveling screen, and backwash pump on top of the structure.

1.2.5.6 WATER TREATMENT

1.2.5.6.1 CHLORINATION. Provide chlorinator and storage for one ton chlorine containers for chlorination of the circulating water, if needed to control sea life growth. Chlorine concentration should be closely controlled and monitored to avoid injury to fish and/or loss of fish life.

1.2.5.6.2 CATHODIC PROTECTION. Provide all equipment necessary to protect exterior surfaces of the water screens, pumps, and piping below the water from corrosion by cathodic protection.

1.2.5.7 HOUSING. For unfavorable weather conditions, house the equipment on top of the structure, provide roof hatches over the screens and pumps to enable removal of the pumps, and include an inside crane. For outdoor installations, the screens and pumps must be raised by some other means of hoisting such as a traveling gantry crane, temporary rigging and hoist, or mobile boom hoist or cranes.

1.2.6 OUTFALL STRUCTURES. Discharge of cooling water from the condenser is made through conduits terminating at an outfall structure (usually made of concrete) located at the shore of an ocean, lake, basin, or river. The purpose of the outfall structure is to control the discharge of cooling water in such a manner to avoid bank or bottom erosion of the main body of water. Because of its location at the end of the discharge conduit, the outfall structure can also be used to provide the necessary seal for cooling water systems operating with a siphon.

1.2.6.1 LOCATION. Locate the end or ends of the discharge conduit downstream from or as far from the intake structure as feasible, in order to reduce the possibility of recirculation of the warm discharge water. Where economically justified, consider bypassing some of the discharge water to the intake structure for controlling ice formations or sea life growth.

1.2.6.2 SEAL WELLS. Where the top of the condenser water box is above extreme low water level of the cooling water source, advantage may be taken of the siphon effect to reduce the total pumping head. In order to start and maintain the siphon, the discharge end of the cooling water conduit must be maintained below water in order to provide and maintain a seal between the water in the conduit and the atmosphere. The maximum practical differential elevation between the extreme low water level of the source and the top of the condenser water box is usually between 28 and 30 feet. The actual value is limited by the vapor pressure of the cooling water corresponding to the actual maximum temperature of the cooling water at the point of maximum vacuum (resulting from the siphon). If, during operation, this limit should be exceeded as a result of higher vacuum or higher water temperature, the cooling water at this point will partially flash into vapor (steam) and the siphon will collapse. Where the maximum allowable siphon is exceeded because of difference in elevation between the water level of the source and top of the condenser water box, a seal well with an adjustable discharge weir must be provided at the end of the discharge conduit to limit the siphon head. The adjustable weir is made up of stop logs that are installed by the operators as necessary to obtain the maximum possible head recovery, which can be afforded by the maximum practical siphon.

1.2.7 COOLING TOWERS. Cooling towers consist of a structure, some type of fill to break the warm water into droplets, warm water distribution system, air circulation system, and basin for collection of cooled water. For a detailed description of construction and theory of operation of cooling towers, see American Society of Heating, Refrigerating, and Air Conditioning Engineers, ASHRAE Handbook, Equipment Volume.

1.2.7.1 MECHANICAL DRAFT TOWERS

1.2.7.1.1 INDUCED DRAFT WET TYPE. This type utilizes propeller fans with exhaust velocity recovery fan cylinders, which are mounted at the top of the cooling tower at the fan deck. Typical fan size for power plant use would be 28-foot diameter and powered with a 200 hp motor (single or two-speed) through a right angle gear reducer. Atmospheric air is drawn in through louvers or grating, through the falling water and fill, through drift eliminators, and out through the fans and fan cylinders.

1.2.7.1.2 INDUCED DRAFT WET/DRY TYPE. This type combines a wet type as described above with a finned tube heat exchanger. The warm water to the tower usually flows first through the heat exchanger and then is distributed over the fill of the wet section. Atmospheric air is drawn in through the heat exchangers in parallel with air through the wet section. The addition of the heat exchanger reduces water consumption and water vapor discharge.

1.2.7.1.3 INDUCED DRAFT DRY TYPE. This combines induced draft fans and finned tube heat exchanger surface. Water flows through the coils while air is drawn across the outside of the finned tubes.

1.2.7.2 NATURAL DRAFT TOWERS. Natural draft cooling towers are generally economical for use only with very large scale power generating plants.

1.2.8 COOLING WATER SYSTEM CHEMICAL TREATMENT

1.2.8.1 CHEMICAL ANALYSIS. The chemical analysis, the source, and the physical analysis of the raw water should be examined to determine what treatments are necessary.

1.2.8.2 SELECTION FACTORS. See Table 1 for a general guide to avoiding circulating water troubles. For collateral reading on the problem, see ASHRAE Handbook, Systems Volume, Corrosion and Water Treatment, and National Association of Corrosion Engineers (NACE), Cooling Water Treatment Manual.

Water problem	Treatment for systems	
	Once through	Open recirculating
Scale	Polyphosphates. pH control. Manual cleaning.	Continuous blowdown. Polyphosphates. pH control. Softening.
Corrosion	Corrosion resistant materials. Coatings. Corrosion inhibitors. pH control.	Corrosion resistant materials. Coatings. Corrosion inhibitors. pH control.
Erosion	Erosion resistant materials. Velocity limit. Removal of abrasives.	Erosion resistant materials. Velocity limit. Removal of abrasives.
Slime and algae	Chlorination. Chemicals, algaecides, slimicides.[1] Manual cleaning.	Continuous blowdown. Chemical algaecides. Velocity. Manual cleaning.
Delignation of wood	none	pH control
Fungus rot	None	Pretreatment of wood

1. Biodegradable materials should be used to avoid environmental damage to streams.

Table 1

Cooling water treatments

2. TESTING

2.1 EQUIPMENT TESTING

2.1.1 TURBINE GENERATORS. Turbine generators shall be tested in accordance with ASME Performance Test Code, PTC 6.1 Interim Test Code for An Alternative Procedure for Testing Steam Turbines.

a) The following are the major measurements which must be made for a condensing turbine in a reheat regenerative cycle using superheated inlet steam. Measurements for a non-reheat, back pressure, or automatic extraction turbine are similar in principle.

1) HP turbine throttle temperature.
2) HP turbine throttle pressure.
3) HP turbine exhaust pressure.
4) HP turbine first stage pressure.
5) Cold reheat temperature.
6) IP Turbine throttle temperature.
7) IP Turbine throttle pressure.
8) LP Turbine throttle temperature.
9) LP Turbine throttle pressure.
10) LP Turbine exhaust pressure.
11) Generator output.
12) Generator hydrogen pressure.
13) Generator power factor.
14) Boiler feed pump discharge temperature.
15) Boiler feed pump discharge pressure.
16) Superheater spray flow.
17) Reheater spray flow.
18) Highest pressure feedwater heater feedwater inlet temperature.
19) Highest pressure feedwater heater feedwater outlet temperature.

20) Highest pressure feedwater heater drain outlet temperature.
21) Highest pressure feedwater heater extraction temperature.
22) Highest pressure feedwater heater extraction pressure.
23) Feedwater flow to boiler.
24) Feedwater pressure at boiler inlet.
25) HP Turbine gland leakage flow.
26) HP Turbine gland leakage temperature.
27) HP Turbine gland leakage pressure.
28) Main steam flow to steam seal receiver.

b) As a result of calculations based on PTC 6S methods, the following performance parameters can be quantified.

1) Maximum capability.
2) Heat rate.
3) Enthalpy-drop efficiency.

2.1.2 STEAM GENERATORS. Steam generators shall be tested in accordance with ASME Performance Test Code, PTC 4.1, Steam Generating Units, which is being revised. The changes which have been incorporated into the latest draft code, such as the use of continuous analyzers instead of Orsat analyzers, are recommended for use.

2.1.2.1 INPUT/OUTPUT METHOD

a) The following are the major measurements which must be made for input/output method.

1) Coal flow.
2) Higher heating value.
3) Combustion air temperature.
4) Feedwater flow.

5) Feedwater temperature.

6) Feedwater pressure.

7) Superheat desuperheat spray flow.

8) Superheat desuperheat spray temperature.

9) Superheat desuperheat spray pressure.

10) Blowdown flow.

11) Auxiliary steam flow.

12) Auxiliary steam temperature.

13) Auxiliary steam pressure.

14) Sootblowing steam flow.

15) Main steam temperature.

16) Main steam pressure.

17) Cold reheat steam pressure.

18) Cold reheat steam temperature.

19) Hot reheat steam pressure.

20) Hot reheat steam temperature.

In addition to these measured parameters, cold reheat flow is required. This can be determined under the turbine generator test.

b) As a result of calculations based on PTC 4.1 methods, the following performance parameters can be quantified.

1) Steam generator efficiency.

2) Input.

3) Output.

4) Steam temperature and control range.

5) Capacity.

6) Water and steam side pressure drop.

2.1.2.2 HEAT LOSS METHOD

a) The following are the major measurements which must be made for heat loss method.

1) Auxiliary steam flow from steam generator.
2) Auxiliary steam temperature.
3) Auxiliary steam pressure.
4) Blowdown flow.
5) Carbon monoxide at economizer outlet.
6) Coal flow.
7) Cold reheat pressure.
8) Cold reheat temperature.
9) Cold reheat flow (calculated by PTC 6 methods).
10) Drum pressure.
11) Feedwater flow at economizer inlet.
12) Feedwater pressure at economizer inlet.
13) Feedwater temperature at economizer inlet
14) Flue gas temperature at air heater outlet.
15) Hot reheat pressure.
16) Hot reheat temperature.
17) Main steam pressure.
18) Main steam temperature.
19) Motor power.
20) Flue gas oxygen at economizer outlet.
21) Pulverizer reject flow.
22) Reheat desuperheating spray flow.
23) Reheat desuperheating spray pressure.
24) Reheat desuperheating spray temperature.
25) Sootblowing steam flow.
26) Sootblowing steam temperature.
27) Sootblowing steam pressure.

29) Superheat desuperheating spray flow.
30) Superheat desuperheating spray temperature.
31) Superheat desuperheating spray pressure.

In addition to these measured parameters, a fuel ultimate analysis, fuel heating value, and ash (if any) heating values are required.

b) As a result of calculations based on PTC 4.1 methods, the following performance parameters can be quantified.

1) Steam generator efficiency.
2) Steam generator steam flow.
3) Steam temperature and control range.
4) Exit flue gas temperature.
5) Water and steam side pressure drop.
6) Steam generator maximum capability.

2.1.2.3 CONDENSERS. Condensers shall be tested in accordance with ASME Performance Test Code, PTC 12.2 Steam Condensing Apparatus.

a) The following are the major measurements which must be made.

1) Circulating water flow.
2) Condenser pressure.
3) Condenser inlet cooling water pressure.
4) Condenser inlet cooling water temperature.
5) Condenser outlet cooling water pressure.
6) Condenser outlet cooling water temperature.
7) Condenser absolute pressure.

b) As a result of calculations based on PTC 12.2 methods, the following performance parameters can be quantified.

1) Condenser tube cleanliness factor.
2) Condenser tube fouling factor.
3) Condenser waterside pressure drop.
4) Condenser heat load.

2.1.2.4 COOLING TOWERS. Cooling towers shall be tested in accordance with The Cooling Tower Institute's (CTI), ATC 105, Acceptance Test Code For Water Cooling Towers (Part 1, Test Procedure: Part 2, Evaluation of Results). ATC 105 recognizes two methods for evaluating the performance of a cooling tower: the characteristic curve method and the performance curve method. Both methods require the same measured data and calculate the same performance parameter. The following are the major measurements which must be made.

a) Wet bulb temperature at tower inlet.
b) Dry bulb temperature.
c) Cold water temperature.
d) Hot water temperature.
e) Cooling water flow.
f) Fan power.
g) Makeup water temperature.
h) Makeup water flow.
i) Blowdown temperature.
j) Blowdown flow.

As a result of calculations, the cooling tower capability can be quantified as a percent of design.

2.1.2.5 EVAPORATORS. Evaporators shall be tested in accordance with ASME Performance Test Code, PTC 14, Evaporating Apparatus.

a) The following are the major measurements which must be made.

1) Evaporator feedwater flow.
2) Evaporator feedwater temperature.
3) Evaporator vapor sample.
4) Evaporator vapor pressure.
5) Evaporator vapor temperature.
6) Steam supply pressure.
7) Steam supply temperature.

b) As a result of tests and determinations based on PTC 14 methods, the following performance parameters can be quantified.

1) Maximum capacity.
2) Total solids in vapor.

2.1.2.6 DEAERATORS. Deaerators shall be tested in accordance with Performance Test Code, PTC 12.3, Deaerators. ASME PTC 12.3 Part II describes several methods of determining the dissolved oxygen content in deaerated water. These methods include the titration method and the colorimetric method. Continuous oxygen analyzers are also commercially available.

2.1.2.7 PUMPS. Centrifugal pumps shall be tested in accordance with ASME Performance Test Code, PTC 8.2, Centrifugal Pumps.

a) The following are the major measurements which must be made for each pump.

1) Inlet flow.

2) Inlet temperature.
3) Inlet pressure.
4) Discharge flow.
5) Discharge temperature.
6) Discharge pressure.
7) Bleedoff flow.
8) Bleedoff temperature.
9) Bleedoff pressure.
10)Pump input power.
11) Pump speed.

b) As a result of calculations based on PTC 8.2 methods, the following performance parameters can be quantified.

1) Capacity.
2) Pump total head.
3) Pump power.
4) Pump efficiency.
5) Suction requirements.
6) Available net positive suction head.
7) Specific speed.

2.1.2.8 FANS. Forced draft and induced draft fans shall be tested in accordance with ASME Performance Test Code, PTC 11, Fans.

a) Test Code PTC 11 recognizes two methods for expressing fan performance.

1) Mass flow/specified energy.
2) Volume flow/pressure.

The mass flow/specific energy method requires velocity and static pressure measurements at the fan inlet and outlet. Experience has shown that accurate velocity pressure measurements at the fan outlet are at best very difficult. Therefore, the volume flow/pressure method which does not require fan outlet velocity pressure is recommended.

b) The following are the major measurements required for the volume flow/pressure method.

1) Fan inlet static pressure.
2) Fan inlet velocity pressure.
3) Fan outlet static pressure.
4) Air or gas inlet temperature.
5) Fan speed.
6) Fan input power.

In addition to these measured parameters, the air or gas composition isrequired.

c) As a result of calculations based on PTC 11 methods, the following performance parameters can be quantified.

1) Fan static pressure.
2) Volumetric flow.
3) Mass flow.
4) Fan static efficiency.

2.1.2.9 COMPRESSORS. Air compressors shall be tested in accordance with ASME Performance Test Code, PTC 9 Displacement Compressors, Vacuum Pumps and Blowers.

a) The following are the major measurements which must be made.

1) Capacity.

2) Inlet static pressure.

3) Discharge static pressure.

4) Stage inlet static pressure (for multistage machines).

5) Stage outlet static pressure (for multistage machines).

6) Inlet air or gas temperature.

7) Intercooler inlet and outlet gas temperatures (for multistage machines).

8) Discharge air or gas temperature.

9) Cooling water flows to individual cylinders and coolers.

10) Cooling water inlet temperatures to individual cylinders and coolers.

11) Cooling water outlet temperatures to individual cylinders and coolers.

12) Compressor speed.

13) Input power.

14) Indicated power.

In addition to these measured parameters, the gas composition is required.

b) As a result of calculations based on PTC 9 methods, the following performance parameters can be quantified.

1) Compression ratio.

2) Isentropic power.

3) Volumetric efficiency.

4) Stage compression efficiency.

5) Mechanical efficiency.

6) Compressor efficiency.

7) Power economy (units of power per unit of capacity).

2.1.2.10 HEAT EXCHANGERS. Feedwater heaters and auxiliary cooling water heat exchangers shall be tested in accordance with ASME Performance Test Code, PTC 12.1 Closed Feedwater Heaters.

a) Feedwater Heaters. The following are the major measurements which will be required for each closed feedwater heater.

1) Feedwater flow.
2) Feedwater inlet temperature.
3) Feedwater outlet temperature.
4) Feedwater inlet pressure.
5) Feedwater outlet pressure.
6) Drain inlet flow (where applicable).
7) Drain inlet pressure (where applicable).
8) Drain inlet temperature (where applicable).
9) Drain outlet flow.
10) Drain outlet temperature.
11) Drain outlet pressure.
12) Extraction steam flow (can be calculated).
13) Extraction steam temperature.
14) Extraction steam pressure.
15) Heater pressure.

In addition to these measured parameters, the heater manufacturer's design data is also required.

b) As a result of calculations based on PTC 12.1 methods, the following performance parameters can be quantified.

1) Terminal temperature difference.
2) Feedwater temperature rise.

3) Drain cooler approach (where applicable).

4) Feedwater pressure drop.

5) Pressure drop through drain cooler (where applicable).

c) Auxiliary Cooling Water Heat Exchangers. Using PTC 12.1, the cooling water heat exchanger will be treated as an external drain cooler. The following are the major measurements which must be made.

1) Tube side water inlet temperature.

2) Tube side water inlet pressure.

3) Tube side water outlet temperature.

4) Tube side water outlet pressure.

5) Shell side inlet temperature.

6) Shell side inlet pressure.

7) Shell side outlet temperature.

8) Shell side outlet pressure.

9) Tube side flow.

10) Shell side flow.

d) As a result of calculations based upon PTC 12.1 methods, the following performance parameters can be quantified.

1) Tube side pressure drop.

2) Shell side pressure drop.

3) Approach temperature.

2.1.2.11 AIR HEATERS. Boiler tubular and regenerative air heaters shall be tested in accordance with ASME Performance Test Code, PTC 4.3 Air Heaters, which is currently being revised as PTC 41. The changes which have been incorporated in developing PTC 41 are recommended for use.

a) The following are the major measurements which must be made for each air heater.

1) Flue gas inlet temperature.
2) Flue gas outlet temperature.
3) Air inlet temperature.
4) Air outlet temperature.
5) Air inlet flow.
6) Air outlet flow.
7) Flue gas inlet flow
8) Flue gas outlet flow.
9) Flue gas side inlet and outlet static pressure.
10) Flue gas side inlet and outlet velocity pressure.
11) Air side inlet and outlet static pressure.
12) Air side inlet and outlet velocity pressure.
13) Inlet flue gas analysis (CO_2, CO, O_2).
14) Outlet flue gas analysis (CO_2, CO, O_2).
15) Fuel flow (measured or calculated by steam generator output and efficiency).

b) In addition to these measured parameters, a fuel ultimate analysis is required. As a result of calculations based on PTC 41 methods, the following performance parameters can be quantified.

1) Flue gas side efficiency.
2) Air leakage.
3) Heat capacity ratio (X-Ratio).
4) No leakage exit flue gas temperature.
5) Flue gas side pressure drop.
6) Air side pressure drop.

2.1.2.12 DUST COLLECTORS. Mechanical dust collectors shall be tested in accordance with ASME Performance Test Code, PTC 21 Dust Separating Apparatus except Environmental Protection Agency Method 5 (40 CFR Part 60 Appendix A, Reference Methods), sampling (isokinetic sampler with heated filter) should be used. Measurements taken include particulate concentration and mass flow rate at both the inlet and outlet of the dust collector. Flue gas flow rate, composition, and temperature are also measured. Measurements at the inlet and outlet allow determination of dust collector overall efficiency.

2.1.2.13 PRECIPITATORS. Electrostatic precipitators shall be tested for performance and compliance (if required by Federal, state, or local regulations). Testing will be the same as described above under Dust Collectors.

2.1.2.14 FLUE GAS SCRUBBERS. Flue gas scrubbers shall be tested for performance and compliance (if required by Federal, state, or local regulations). An ASME performance test code is in the process of preparation, however, no interim PTC for scrubbers is yet available. Testing should be done in accordance with 40 CFR Part 60 Appendix A, EPA Method 5 or 17 for particulate matter and Methods 6 and 8 for SO_2, SO_3, and NOx.

2.2 PREPARATIONS FOR TESTS. Preparations for testing includes the following.

a) Determine applicable test code.

b) Read and observe applicable parts of ASME PTC 1, General Instructions and ASME PTC 2, Definitions and Values.

c) Determine test data and readings required.

d) Prepare necessary forms for recording of test data.

e) Determine instrumentation to be used for tests and provide temporary supplemental instruments as necessary.

f) Calibrate or verify calibration of instruments.

g) Determine the necessary parties to the test.

2.3 TEST EQUIPMENT AND MATERIALS. The test equipment shall consist of instruments and apparatus as necessary to provide indication or record of test properties and variables. Materials shall consist of miscellaneous chemicals for charging instruments and supplies. Each individual test code for specific equipment contains information covering permissible choices of instrumentation, methods of calibration, and precautions to be observed. Whether cited or not in the test code, Supplements to ASME Performance Test Code, PTC 19 Instruments and Apparatus should be consulted as necessary. These supplements are as follows:

a) PTC 19.2 Pressure Measurement.
b) PTC 19.3 Temperature Measurement.
c) PTC 19.5 Application, Part II of Fluid Meters: Interim
Supplement on Instruments and Apparatus.
d) PTC 19.5.1 Weighing Scales.
e) PTC 19.6 Electrical Measurements in Power Circuits.
f) PTC 19.7 Measurement of Shaft Power.
g) PTC 19.8 Measurement of Indicated Horsepower.
h) PTC 19.10 Flue and Exhaust Gas Analyses - Instruments & Apparatus - V Part 10.
i) PTC 19.12 Measurement of Time.
j) PTC 19.13 Measurement of Rotary Speed.
k) PTC 19.14 Linear Measurements.
l) PTC 19.16 Density Determinations of Solids and Liquids.
m) PTC 19.17 Determination of the Viscosity of Liquids.